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BEFORE THE ARIZONA CORPORATION

Arizona Corporation Commission
DOCKETED

JUN 11 2008

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COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650 **NOTICE OF FILING**

Staff of the Arizona Corporation Commission hereby provides notice of filing of the Direct Testimony of Ernest Johnson, Barbara Keene, Frank Radigan, and Ralph Smith in support of the Proposed Settlement Agreement filed in the above-referenced matter.

RESPECTFULLY SUBMITTED this 11th day of June, 2008.

Nancy L. Scott

Janet Wagner, Assistant Chief Counsel
Robin Mitchell. Attorney
Nancy L. Scott, Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

AZ CORP COMMISSION
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RECEIVED

Original and 15 copies of the foregoing filed this 11th day of June, 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing delivered via electronic mail this 11th day of June, 2008 to:

Michael Grant
Gallagher & Kennedy, PA
2575 East Camelback Road
Phoenix, Arizona 85016-9225
mmg@gknet.com

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004
thogan@aclpi.org

David Berry
WESTERN RESOURCE ADVOCATES
Post Office Box 1064
Scottsdale, Arizona 85252-1064
azbluhill@aol.com

Gary Yaquinto, President
Arizona Investment Council
2100 North Central Ave., Suite 210
Phoenix, Arizona 85004
gyaquinto@arizonaic.org

Jeff Schlegel
SWEEP
1167 West Samalayuca Drive
Tucson, Arizona 85704-3224
schlegelj@aol.com

Peter Q. Nyce, Jr.
DEPARTMENT OF THE ARMY
901 North Stuart Street
Arlington, Virginia 22202-1837
peter.nyce@us.army.mil

Dan Neidlinger
NEIDLINGER & ASSOCIATES
3020 North 17th Drive
Phoenix, Arizona 85015
dneid@cox.net

Meghan Grabel, Esq.
Thomas L. Mumaw, Esq.
PINNACLE WEST CAPITAL CORPORATION
400 North 5th Street, MS 8695
Phoenix, Arizona 85004
thomas.mumaw@pinnaclewest.com
meghan.grabel@pinnaclewest.com

Scott S. Wakefield, Chief Counsel
RUCO
1110 West Washington St., Suite 220
Phoenix, Arizona 85007
swakefield@azruco.gov
egamble@azruco.gov

Christopher Hitchcock
Law of Office of Christopher Hitchcock, P.L.C.
1 Copper Queen Plaza
Post Office Box AT
Bisbee, Arizona 85603-0115
lawyers@bisbeelaw.com

Raymond S. Heyman
Senior Vice President and General Counsel
UNISOURCE ENERGY CORPORATION
One South Church Ave., Suite 1820
Tucson, Arizona 85701
rheyman@uns.com

Michelle Livengood
TUCSON ELECTRIC POWER COMPANY
One South Church Avenue, Suite 200
Tucson, Arizona 85701
mlivengood@tep.com
dcouture@tep.com

Michael W. Patten, Esq.
ROSHKA DeWULF & PATTEN
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
mpatten@rdp-law.com
mippolito@rdp-law.com

Barbara A. Klemstine
Brian Brumfield
Arizona Public Service
P.O. Box 53999
Mail Station 9708
Phoenix, Arizona 85072-3999
Barbara.Klemstine@aps.com
Susan.Casady@aps.com

C. Webb Crockett
FENNEMORE CRAIG, PC
3003 North Central Ave., Suite 2600
Phoenix, Arizona 85012-2913
wcrocket@fclaw.com
pblack@fclaw.com
khiggins@energystrat.com

Copies of the foregoing mailed this 11th day of June, 2008 to:

Michael W. Patten, Esq.
ROSHKA DeWULF & PATTEN
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Michelle Livengood
TUCSON ELECTRIC POWER COMPANY
One South Church Avenue, Suite 200
Tucson, Arizona 85701

Lawrence Robertson, Jr.
P.O. Box 1448
Tubac, Arizona 85646

Deborah A. Scott
Robert J. Metli
SNELL & WILMER LLP
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004-2202

Eric Guidry
Energy Program Staff Attorney
WESTERN RESOURCE ADVOCATES
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Nicholas J. Enoch
LUBIN & ENOCH, PC
349 North Fourth Avenue
Phoenix, Arizona 85003

Greg Patterson, Director
Arizona Competitive Power Alliance
916 West Adams, Suite 3
Phoenix, Arizona 85007

Daniel D. Haws
OSJA, ATTN: ATZS-JAD
USA Intelligence Center and
Ft. Huachuca
Ft. Huachuca, Arizona 85613-6000

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Billy L. Burtnett
3351 North Riverbend Circle East
Tucson, Arizona 85750-2509

John E. O'Hare
3865 North Tucson Boulevard
Tucson, Arizona 85716

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016

Roseann Osorio

DIRECT TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

ERNEST G. JOHNSON

RALPH C. SMITH

BARBARA E. KEENE

FRANK W. RADIGAN

DOCKET NO. E-01933A-07-0702

DOCKET NO. E-01933A-05-0650

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103

JUNE 11, 2008

Johnson

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGH OUT THE STATE OF ARIZONA	DOCKET NO. E- 01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

ERNEST G. JOHNSON

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 11, 2008

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TESTIMONY SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-07-0402 & E-01933A-05-0650

Mr. Johnson provides policy level testimony which summarizes the Settlement process, provides reasons which support Staff's conclusions that the Settlement Agreement is in the public interest, and addresses several general policy considerations.

Staff's remaining witnesses will provide a detailed summary for each applicable subject area; by contrast, Mr. Johnson's testimony addresses the Settlement from a policy perspective. Mr. Johnson concludes that the Settlement Agreement is fair, balanced, and in the public interest. Mr. Johnson asserts the following as support for Staff's conclusion that the Settlement Agreement is in the public interest:

- Staff believes that the Agreement is fair to ratepayers because it results in just and reasonable rates for consumers.

- Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service along with an opportunity for a reasonable profit.

- Staff believes that the Agreement promotes rate stability by establishing a four-year base rate increase moratorium.

- Staff believes that this proposal balances many diverse interests, including those of low-income, residential, commercial, and industrial customers, merchant generators, retail energy marketers, and shareholders.

- Staff believes that the Settlement will allow the elimination of long, complex litigation by resolving issues associated with prior Commission decisions.

- Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at the lowest reasonable rates.

Staff believes that the agreement promotes the public interest by providing tangible benefits to the public such as:

- Establishes a four-year moratorium on base rate increases.
- Provides for no base rate increase to low-income customers.
- Limits the base rate increase to approximately 6%.
- Implements a demand-side management adjustor and performance incentive.
- Provides for expanded time-of-use options to customers.
- Retains cost-of-service-based rate making treatment.

Finally, in concluding that the Settlement Agreement is in the public interest, Mr. Johnson notes that the Agreement addresses and resolves all of the main rate case issues, provides sufficient revenues and return for TEP to maintain reliable electric service, and results in rates and charges which Staff believes are just and reasonable.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ernest G. Johnson, 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as the Director of the Utilities Division.

Q. Briefly describe your responsibilities as Utilities Director.

A. I am responsible for the day-to-day operations of the Utilities Division, including policy development, case strategy, and overall Division management.

Q. Please summarize your educational background and professional experience.

A. In 1979 and 1982, respectively, I earned Bachelor of Science and Juris Doctorate degrees, both from the University of Oklahoma. I have been involved in the regulation of public utilities since 1986. I was employed by the Oklahoma Corporation Commission in 1986 in various legal capacities. In 1993, I was named acting Director and served in that position until mid-1994. I served as permanent Director from mid-1994 until October 2001. In October of 2001, I assumed my current position with the Arizona Corporation Commission. While serving in these capacities, I have participated in numerous regulatory proceedings, including providing policy analysis concerning Electric Restructuring before the Oklahoma Corporation Commission, the Oklahoma State Legislature, and the Arizona Commission.

Q. Did you participate in the negotiations that led to the execution of the Proposed Agreement?

A. Yes, I did.

Q. What is the purpose of your testimony in this case?

A. I will provide testimony which addresses the Settlement process, public interest Settlement benefits, and general policy considerations.

Q. How is your testimony being presented?

A. My testimony is organized into three sections. Section I provides discussion and insight into the Settlement process. Section II identifies and discusses the reasons why the Settlement Agreement ("Agreement") is in the public interest. Section III addresses several general policy considerations. Section IV is responsive to Commissioner Mayes May 20, 2008, letter filed in the docket.

Q. Who else is providing Staff testimony, and what issues will they address?

A. Staff will present the following witnesses:

Staff's Consultant Ralph Smith will be covering in more detail the technical areas of revenue deficiency, accounting, and depreciation rates as well as the following sections of the Settlement Agreement:

I	Rate Increase
II	Ratemaking Treatment of TEP's Generation Assets and Fuel Costs
III	Cost of Capital
IV	Depreciation and Cost of Removal
V	Implementation Cost Recovery Asset

VI Purchased Power and Fuel Adjustment Clause

VII Fixed CTC True-Up Revenues

VIII Fuel Audit

Staff Witness Barbara Keene will be covering in more detail the Settlement Sections that pertain directly to the following:

- Renewable Energy Adjustor/Renewable Energy Commitment.
- Demand-Side Management Programs and Adjustor.
- New partial requirements Tariffs.
- Interruptible Tariff.
- Demand Response Program

Staff Witness Frank Radigan will be covering in more detail the Settlement Sections that pertain to the following:

Rate Design that includes:

- Inclining Block Rate.
- Time of Use.
- Other Rate Design Changes.

SECTION I – SETTLEMENT PROCESS

Q. Please discuss the Settlement process.

A. The Settlement process was open, transparent, and inclusive. All parties received notice of the Settlement meetings and were accorded an opportunity to raise, discuss, and propose resolution to any issues that they desired.

Q. How many Settlement meetings were held?

A. There were approximately eight large group Settlement meetings relating to revenue requirement and rate design. In addition, there were numerous other discussions involving individual parties.

Q. Who participated in those meetings?

A. The following parties were participants in all or some of the Settlement meetings: Tucson Electric Power Company ("TEP"), the Residential Utility Consumer Office ("RUCO"), Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company (collectively, "AECC"), Arizona Community Action Association ("ACAA"), U.S. Department of Defense and all other Federal Executive Agencies ("DOD"), Arizona Investment Council ("AIC"), Southwest Energy Efficiency Project ("SWEEP"), International Brotherhood of Electrical Workers Local 1116 ("IBEW 1116"), Kroger Company, Mesquite Power LLC et al, and the Arizona Corporation Commission Utilities Division ("Staff").

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. Diverse interests included consumer representatives, merchant plants, large customers of TEP, DOD, and demand side management ("DSM") advocates, just to name a few.

Q. How many of these parties executed the stipulation?

A. The Agreement was executed by Staff, TEP, AECC, ACAA, DOD, AIC, IBEW 1116, Kroger Co., and Mesquite Power LLC et al.

Q. Were there parties who chose not to execute the Agreement?

A. Yes, RUCO and SWEEP chose not to execute the Agreement.

Q. Why did RUCO and SWEEP choose not to execute the Agreement?

A. I don't know.

Q. In your opinion, was there an opportunity for all issues to be discussed and considered?

A. Yes. In my opinion, each party had the opportunity to raise and have their issues considered.

Q. Were the signatories able to resolve all issues?

A. No. As discussed later in my testimony, issues related to the treatment of the Fixed Competitive Transition Cost true-up ("Fixed CTC TRUE-UP") revenues remain unresolved by this Agreement. The signatories agreed to present their respective positions at the hearing. In addition, the issue of when new rates should become effective is not resolved by the Agreement.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented the interests of their constituents. I would characterize the discussions as candid but professional. I am extremely pleased with the desire and effort put forth by all parties. While acknowledging that not all parties executed the Agreement, I must note that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Mr. Johnson, would you describe the process as requiring a lot of give and take?

A. Yes, I would. As a result of the many and varied interests represented in the Settlement process, a willingness to compromise was absolutely necessary. As evidenced in the Agreement, the signatories compromised vastly different litigation positions.

Q. In your previous response, you stated that the parties were able to settle various litigation positions. Is that correct?

A. Yes.

Q. In your opinion, was the public interest unduly compromised?

A. No, not in my opinion. As I will discuss later in this testimony, I believe that the compromises made by the various parties will actually further the public interest.

Q. Mr. Johnson, are there any other comments you would like to make in regard to the Settlement process?

A. Yes. In my view, the Settlement process resulted in an Agreement which some may not view as perfect but nonetheless is balanced and consistent with the public interest.

SECTION II - PUBLIC INTEREST

Q. Let us turn now to the issue of public interest. Mr. Johnson, in Staff's opinion, is the Proposed Settlement in the public interest?

A. Yes, absolutely. In Staff's opinion, the Proposed Settlement is fair, balanced, and in the public interest.

Q. Mr. Johnson, would you briefly summarize the reasons that Staff concludes that the Settlement is fair, balanced, and in the public interest.

A. Yes, the following reasons support Staff's view:

- Staff believes that the Agreement is fair to ratepayers because it results in just and reasonable rates for consumers.

- Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service along with an opportunity for a reasonable profit.

- Staff believes that this proposal balances many diverse interests, including those of low-income, residential, commercial, and industrial customers, merchant generators, retail energy marketers, and stakeholders.

- Staff believes that the Settlement will allow the elimination of long, complex litigation by resolving issues associated with prior Commission decisions.

- Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at the lowest reasonable rates.

Q. Are there other reasons why Staff believes the Agreement promotes the public interest?

A. Yes, some of the benefits of the Settlement Agreement include:

- Establishes a four-year moratorium on base rate increases.
- Provides for no base rate increase for low-income customers.
- Limits the base rate increase to approximately 6%.
- Provides for expanded time-of-use options to customers.
- Implements a demand-side management adjuster and performance incentive.
- Retains cost-of-service-based rate-making treatment.

Q. Turning to your first point, you suggest that the Settlement results in just and reasonable rates for consumers. Please explain.

A. In its 2007 Rate Application, TEP proposed three alternative rate methodologies. They were identified as Market, Cost of Service, and Hybrid. Each of these proposals would have increased base rates in excess of two-hundred million dollars ($212 million to $275 million) and would have increased rates (14.9% to 23%). Staff reviewed TEP's application and concluded that the base rate increases proposed by the Company were excessive as set forth in the direct testimony filed by Staff.

Q. Did TEP file rebuttal testimony responding to Staff?

A. Yes, TEP filed rebuttal testimony significantly disagreeing with Staff's direct testimony.

Q. Did Staff file Surrebuttal Testimony?

A. No, settlement discussions ensued prior to the date established by the procedural order for the filing of surrebuttal testimony by Staff and other parties.

Q. Mr. Johnson, if Staff had filed surrebuttal testimony, would its recommendation regarding revenue requirement have been different from the position set forth by Staff in its Direct Testimony?

A. Yes, but this issue would be best addressed by Staff witness Ralph Smith, who is addressing revenue requirement related issues in this case.

Q. Mr. Johnson, is it accurate to say that Staff's revenue requirement recommendation would have been much higher than the revenue requirement recommendation contained in its direct testimony?

A. Yes, but again Mr. Smith would be the witness to elaborate on this issue.

Q. Mr. Johnson, with the background you just shared, is it your view that the revenue requirement set forth in the agreement results in appropriate utility revenue and just and reasonable rates for consumers?

A. Yes, that is my opinion.

Q. Please discuss how the Settlement is fair to the utility.

A. Staff believes that the Agreement is fair to the utility because it provides an opportunity for TEP to earn revenues sufficient for the utility to provide reliable electric service and to achieve a reasonable profit. Illustratively, the Settlement would provide TEP with revenues which would allow it an opportunity to earn an overall rate of return of approximately 5.64 percent and a 10.25 percent return on equity. In Staff's opinion, these returns would enable TEP to provide reliable service at reasonable rates.

Q. Mr. Johnson, you have indicated that the Settlement Proposal incorporates many diverse interests, including those of low-income customers, residential, commercial, industrial customers, merchant generators, and retail energy marketers. Please elaborate.

A. Within the Agreement, there are specific provisions which address many of the concerns expressed by the above-referenced interests.

Examples include:

- Four-year base rate moratorium.
- No rate increase for low-income customers.
- Reduced base rate increase.
- Expanded time-of-use options.

Q. Mr. Johnson, you suggested that the Agreement is in the public interest because, if approved, it would eliminate long, complex litigation. Please explain.

A. With Commission approval of the Agreement, several legal matters would be settled, as set forth more fully in Paragraphs 1.4 and 1.5. The Agreement would effectively resolve issues associated with the 1999 Settlement Agreement, including TEP's Motion to Amend the Fixed Competition Transition charge and other matters.

Q. What impact will the Settlement have on low-income customers?

A. As previously stated, the Settlement provides for no increase in base rates to low-income customers. It was the parties' intent to insulate current and future low-income customers from a base rate increase. As a result, if the Agreement is approved, low-income customers would not see a base rate increase in their utility rates, nor would they be subject to the costs associated with the purchased power fuel adjustment clause ("PPFAC").

Q. Please discuss your assertion that the Agreement promotes the public interest by facilitating reliable electric service at the lowest reasonable rates.

A. As previously stated, the Settlement would allow TEP the opportunity to earn an overall return of 5.64 percent and a 10.25 percent return on equity. In Staff's opinion, TEP should have sufficient revenues and reasonable access to capital, which will allow it to properly maintain its system and provide reliable electrical service.

Q. Mr. Johnson, was the treatment of the fixed CTC TRUE-UP revenues addressed in the Settlement Agreement?

A. Yes, Section XV of the Settlement Agreement is intended to address the CTC TRUE-UP issue.

Q. How does Section XV address the issue?

A. Section XV acknowledges the inability of the signatories to reach a substantive resolution of the treatment to be accorded to CTC TRUE-UP revenues. Instead, the signatories agreed to present their respective positions in the hearing.

Q. What specifically will the signatories address at the hearing?

A. The signatories will present their positions as to when new rates should become effective and how TEP's fixed CTC TRUE-UP revenues should be calculated and treated.

Q. Does the Agreement limit the ability of any signatory to present its position on these issues?

A. No, it does not. Paragraph 15.1 clearly acknowledges the ability of any signatory to put forward its own views concerning the treatment of fixed CTC TRUE-UP revenues and the effective date of new rates.

Q. Mr. Johnson, what is Staff's view concerning when new rates should become effective?

A. It is Staff's view that the new rates should become effective no sooner than January 1, 2009. It is Staff's view that this time frame is consistent with the intent of the Commission when it approved the 1999 Settlement Agreement.

Q. Mr. Johnson, what is Staff's view regarding the treatment that should be accorded to the Fixed CTC TRUE-UP revenues?

A. Staff believes that all fixed CTC related TRUE-UP revenues should be used to benefit ratepayers.

Q. Please explain.

A. Paragraph 15.2 of the Settlement Agreement contemplates that Fixed CTC TRUE-UP revenues, up to $32.5 million, will be credited to customers through the PPFAC balancing account. Paragraph 15.3 of the Agreement provides that the Commission will determine the disposition of additional Fixed CTC TRUE-UP revenues, if any, to be credited to customers. In this light, it is Staff's view that any remaining Fixed CTC TRUE-UP revenues should inure to the benefit of customers, either as a future credit to the PPFAC balancing account or as a credit to customers through some other Commission-approved mechanism.

Q. Did TEP agree to a rate moratorium?

A. Section X of the Agreement provides for a moratorium in which TEP's base rates would remain frozen through December 31, 2012. In Section XI, the Agreement also provides an opportunity for TEP to request a change to its base rates and/or adjustors if an emergency were to arise. An emergency is defined in the Agreement as an extraordinary event that is beyond the control of TEP.

Q. Can you please explain the issues and resolution reached in the Settlement Agreement regarding TEP's CC&N and Returning Customer Direct Access Charge?

A. Yes. TEP, in its original filling, requested that the Commission restore the exclusivity of its CC&N. Currently, there are several applications for competitive CC&N pending before the Commission. The Signatories agreed that a generic docket is the appropriate means by which the Commission could address this issue, if the Commission chooses to do so. This result serves to preserve the status quo pending further Commission determinations on this issue.

In addition, the Agreement addresses TEP's obligation to serve all customers in its certificated areas. In conjunction with this treatment of the CC&N issue, Section 13 of the Agreement provides for a returning customer direct access charge. This charge shall apply only to individual customers or aggregated groups of customers with demand load of 3 MWs or greater. The purpose of this charge is to recover from these customers the additional costs, both one-time and recurring, that would otherwise be imposed on other standard offer customers if and when the direct access customers return to standard offer service from their competitive suppliers.

SECTION III - POLICY CONSIDERATIONS

Q. Mr. Johnson, how does Staff reconcile moving from its recommended revenue requirement in its direct testimony to the revenue requirement recommended in the Settlement Agreement?

A. The testimony of Mr. Ralph Smith offers a more complete discussion of the basis for the revenue requirement set forth in the Agreement. In this testimony, I address the policy reasons underlying Staff's support for the revenue requirement set forth in the Agreement.

Q. Mr. Johnson, what was Staff's goal when it agreed to enter into Settlement discussions in this matter?

A. The primary goal of Staff in this matter and all matters before the ACC is to protect the public interest. We believe we accomplished this goal by reviewing the facts presented and making appropriate recommendations to the Commission for its consideration.

Q. Mr. Johnson, do you believe this Settlement protects the public interest?

A. Yes, I do. As stated previously in my testimony, this Agreement strikes an appropriate balance between numerous competing interests. This balance includes the need for TEP's customers to pay rates that are just and reasonable and that allow TEP the opportunity to earn a reasonable return on its investment in providing electric utility services.

Q. Does this Agreement strike an appropriate balance between the diverse needs of the interested parties?

A. Yes, it does. The Agreement provides for:

- Establishment of a Renewable Energy Adjustor.
- Establishment of a DSM Adjustor.
- Establishment of four-year Base Rate Increase Moratorium.
- Expansion of Time-of-use Options.
- Availability of Retail Competitive opportunities.

Q. As a policy matter, why should the Commission approve the Settlement Agreement?

A. The Settlement Agreement addresses and resolves all of the major rate case issues and results in rates which we believe are just and reasonable. Staff believes that the agreed-upon revenue requirement is sufficient for TEP to maintain reliable service to its customers and to provide an opportunity for TEP to earn a fair return for its investors while causing only a modest increase in rates.

SECTION IV - COMMISSIONER MAYES LETTER DATED MAY 20, 2008

Q. Mr. Johnson are you aware that on May 20, 2008, Commissioner Mayes placed a letter in the Docket requesting that the parties address in testimony or settlement the issues raised in that filing?

A. Yes. I have reviewed the above-referenced letter.

Q. Mr. Johnson, does the Agreement address the issues raised by Commissioner Mayes?

A. Generally, yes, but not entirely.

Q. Please explain.

A. In broad terms the letter covers many topics including:

- Renewable Energy
- Partial Requirement Service Tariffs
- Demand Response
- Time of Use
- Demand Side Management
- Low-Income Assistance

Each of the above-referenced items will be addressed in testimony filed by other Staff witnesses.

Q. Mr. Johnson does the Agreement address any renewable issues?

A. Yes, at least in part.

Q. Please explain.

A. Section VIII of the Agreement provides for the establishment of a Renewable Energy Standard Tariff ("REST") adjustor mechanism as recommended by Staff in its Direct Rate Design testimony. Generally speaking, the purpose of this adjustor is to provide for the more expedient recovery of costs associated with implementation of the REST rules. Additionally, should the Commission subsequently determine that escalation of its renewable timetable is appropriate, the Commission could also more expeditiously address cost recovery issues.

Q. Do you have any further comments?

A. Yes. The Commission fairly recently promulgated rules relating to renewable energy. These rules were carefully and thoughtfully drafted and considered by the Commission. Additionally, the rules were drafted and revised in a broad context in which the Commission heard many diverse interests including utility and non-utility participants. More recently, the Commission considered and approved REST implementation plans and tariffs, including those for TEP. In light of the recent actions of the ACC, it did not appear appropriate to Staff to seek to unilaterally modify, enhance or alter the Commission's decisions.

I would note that the other issues raised by Commissioner Mayes have been fairly considered by the signatories and their treatment is reflected in the Settlement Agreement.

Q. Mr. Johnson, do the parties believe an increased commitment to renewable energy is a ratepayer benefit that should be offered as part of the Settlement Agreement?

A. No, Staff does not.

Q. Please explain.

A. Staff believes that the Agreement provides very favorable benefits to ratepayers and as a consequence does not necessitate the inclusion of an increased commitment to renewable energy in order to reach a just and reasonable outcome. Ultimately, this is an issue that would be best determined by the Commission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Smith

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-07-0402
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DIRECT TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 11, 2008

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ATTACHMENTS

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-07-0402 AND E-01933A-05-0650

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

II. Rate Increase
III. Ratemaking Treatment of TEP's Generation Assets and Fuel Costs
IV. Cost of Capital
V. Depreciation and Cost of Removal
VI. Implementation Cost Recovery Asset
VII. Purchased Power and Fuel Adjustment Clause
XV. Fixed CTC True-Up Revenues
XIX. Fuel Audit

My findings and recommendations for each of these areas are as follows:

II. Rate Increase. For Settlement purposes, Staff, TEP, and a number of other parties to this rate case have agreed to a rate increase that would provide TEP with approximately $828.2 million of base rate revenue per year. As shown on Settlement Exhibit 3, page 1, this $828.2 million is approximately a 6 percent increase over TEP's current revenue of $781.1 million. In dollar terms, the base rate increase over TEP's current revenue is approximately $47.1 million. This is also addressed in Paragraph 2.3 of the Settlement. As shown on Settlement Exhibit No. 2, page 2 of 5, TEP's current revenues include approximately $89.6 million for Fixed CTC.

As described in Paragraph 2.1 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2006, of approximately $1.452 billion, and a fair value rate of return of 5.64 percent. Settlement Exhibit No. 1 summarizes the fair value rate base, adjusted operating income, and fair value rate of return that the signing parties used for Settlement purposes to derive a base rate increase amount of approximately $136.8 million.

Settlement Exhibit No. 2 presents the Signatories' approach of reconciling the amount of base rate increase that is provided for in the Settlement. It has columns for TEP's original filing, Staff's direct filing, and the Settlement. It shows how the adjustments originally filed by TEP and Staff were ultimately resolved, for Settlement purposes, in deriving the base rate increase of $136.8 million.

Attachment RCS-7 presents a reconciliation of the jurisdictional revenue deficiency of approximately $9.8 million on original cost rate base ("OCRB") filed with my direct testimony to the $136.8 million increase provided for in the Settlement Agreement. My testimony in support of the Settlement describes the resolution, for Settlement purposes, of a number of major impact items, including Springerville Unit 1, Accumulated Depreciation and prospective depreciation rates, and items such as Short Term Sales Revenue and Gain on Sale of SO2

Allowances. Attachment RCS-8 presents the transcript of my deposition in this proceeding which was taken by TEP on March 10, 2008. In that deposition, a number of the more important issues pertaining to this case were discussed in additional detail

III. Ratemaking Treatment of TEP's Generation Assets and Fuel Costs

Section III of the Settlement Agreement resolves the disputes between the parties concerning the ratemaking treatment of TEP's generation assets. Paragraph 3.1 of the Settlement Agreement provides, for ratemaking purposes, that Springerville Unit 1 and the Luna Generating Station shall be included in TEP's rate base at their respective original costs. Moreover, all other generation assets acquired by TEP after December 31, 2006, but before December 31, 2012, shall be included in TEP's rate base at their respective original costs, subject to the Commission's subsequent regulatory and ratemaking review and approval.

IV. Cost of Capital

The Settlement Agreement provides for an overall cost of capital of 8.03 percent and a 5.64 percent fair value rate of return ("FVROR"). It provides for a return on equity of 10.25 percent, which was the Staff recommendation.

V. Depreciation and Cost of Removal

Section V of the Settlement Agreement addresses depreciation rates. It provides that TEP shall use the depreciation rates contained in Settlement Exhibit No. 5. In general, the depreciation rates for Distribution and General Plant are consistent with TEP's originally filed depreciation study. Additionally, for generation plant, the remaining lives and cost recovery rates are consistent with TEP's revised depreciation study that was filed with TEP witness Kissinger's rebuttal testimony. As a result of Settlement negotiations, an additional provision for increased accruals for cost of removal on TEP's generation plant has been included in the depreciation rates provided for in the Settlement Agreement. This provision is closely related to the compromises the parties reached concerning the amount of Accumulated Depreciation reflected in rate base. It provides for additional build-up for TEP's Accumulated Depreciation balance related to cost-of-removal accruals on generation plant during the rate moratorium period.

VI. Implementation Cost Recovery Asset

Section VI of the Settlement Agreement addresses the ratemaking treatment of the Implementation Cost Recovery Asset ("ICRA"). Consistent with Staff's recommendation, $14.2 million is included in rate base. That amount is amortized over a four-year period, which is also consistent with Staff's recommendation. Amounts in excess of the $14.2 million that were originally requested by TEP have been removed from rate base and from amortization expense. Additionally, Paragraph 6.2 of the Settlement Agreement specifies that the ICRA shall not be included in rate base or as an amortization expense in TEP's next rate case. The timing of when TEP can file its next rate case is addressed in Section X of the Settlement Agreement, which provides for a rate case moratorium.

VII. Purchased Power and Fuel Adjustment Clause

Section VII of the Settlement Agreement addresses the provisions of the PPFAC that has been agreed to by the parties through the process of negotiation. The plan of administration for the PPFAC is provided in Settlement Exhibit No. 6. It is reasonable to provide for the recovery of

TEP's fuel and purchased power costs through a PPFAC. TEP does not currently have a PPFAC. However, TEP does have significant fuel and purchased power costs. For the reasons described in my direct testimony that was filed on February 29, 2008 in this proceeding, it is reasonable to provide for the recovery of TEP's fuel and purchased power costs through a PPFAC.

XV. Fixed CTC True-Up Revenues

Other Staff witnesses are presenting Staff's position concerning the disposition of Fixed CTC True-Up Revenue. I have been asked to provide the estimated amounts of such revenue. Based on the information provided by TEP in response to Staff data request LA-25-1, I have summarized these estimated amounts, by month and cumulatively, in a table on page 19 of my testimony.

XIX. Fuel Audit.

Section XIX of the Settlement Agreement addresses TEP's implementation of the fuel audit recommendations set forth in Staff's direct testimony. TEP has agreed to implement Staff's recommendations. TEP need not complete its implementation of such recommendations prior to implementing the PPFAC. Section XIX provides that TEP should file an implementation plan within 90 days of the effective date of the Commission's order approving the Settlement Agreement.

I. INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on February 29, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-7 presents a reconciliation of the revenue deficiency presented in Staff's Direct Testimony with the revenue deficiency proposed in the Settlement Agreement. Specifically, Attachment RCS-7 presents a reconciliation of the jurisdictional revenue deficiency of approximately $9.8 million on original cost rate base ("OCRB") filed with my direct testimony to the $136.8 million increase provided for in the Settlement Agreement. Attachment RCS-8 is the transcript of my deposition in this proceeding which was taken by TEP on March 10, 2008.

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

II. Rate Increase

III. Ratemaking Treatment of TEP's Generation Assets and Fuel Costs

IV. Cost of Capital

V. Depreciation and Cost of Removal

VI. Implementation Cost Recovery Asset

VII. Purchased Power and Fuel Adjustment Clause

XV. Fixed CTC True-Up Revenues

XIX. Fuel Audit

The numbering of these provisions corresponds with the Settlement Agreement.

II. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, TEP, and a number of other parties to this rate case have agreed to a rate increase that would provide TEP with approximately $828.2 million of base rate revenue per year. As shown on Settlement Exhibit 3, page 1, this $828.2 million is approximately a 6 percent increase over TEP's current revenue of $781.1 million.[1] In dollar terms, the base rate increase is approximately $47.1 million. This is also addressed in paragraph 2.3 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in Paragraph 2.1 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2006, of approximately $1.452 billion, and a fair value rate of return of 5.64 percent. Settlement Exhibit No. 1 summarizes the fair value rate base, adjusted operating income, and fair value rate of return that the signing parties used for Settlement purposes to derive a base rate increase amount of approximately $136.8 million.

[1] As shown on Settlement Exhibit No. 2, page 2 of 5, TEP's current revenues include approximately $89.6 million for Fixed CTC.

Q. What amount of revenue increase had TEP originally requested?

A. As shown on Settlement Exhibit No. 2, page 5 of 5, TEP had originally requested a total base rate increase of approximately $275.8 million under the cost-of-service methodology. As also shown on that Exhibit, TEP's requested $275.8 million increase consisted of two components: (1) approximately $158.2 million of base rate increase, and (2) an additional $117.6 million for TEP's requested "Transition Cost Regulatory Asset Charge" ("TCRAC"), which TEP had requested as a separate surcharge.

Q. How does the amount of rate increase provided for in the Settlement compare with the amount that TEP had originally requested?

A. The base rate increase of $136.8 million provided for in the Settlement is $139 million less than TEP's original request of approximately $275.8 million, under the cost-of-service methodology. Put another way, the $136.8 million is approximately half (49.6 percent) of what TEP had originally requested under the cost-of-service methodology.

Q. Based on your experience, was this TEP rate case more complicated than a typical utility rate case?

A. Yes. The instant TEP rate case included a number of factors that made it considerably more complex than a typical utility rate case. Such factors included TEP's requests for three alternative ratemaking methodologies, TEP's alleged uncertainty about how its generation was to be regulated, TEP's claim for a TCRAC based on Company calculations of past under-earnings, and TEP's assertions concerning the pursuit of legal remedies. All of these factors lent additional complexity to the current TEP rate case.

Q. How does the Settlement treat TEP's request for the TCRAC?

A. The Settlement eliminates TEP's requested TCRAC. As shown on Settlement Exhibit No. 2, page 5, by the zero amounts in the "Direct ACC 2/29/08" and the "Settlement 5/29/08" columns, Staff had recommended that the Commission reject TEP's requested TCRAC. The Settlement adopts Staff's adjustment. The total elimination of TEP's request for the TCRAC from the base rate increase specified in the Settlement Agreement was an important, and perhaps essential, feature in enabling the Settlement to occur.

Q. You mentioned that one of the areas of additional complexity in the current TEP rate case relates to TEP's assertions concerning the pursuit of legal remedies. How does the Settlement provide for the elimination of potentially lengthy and costly future litigation?

A. Another Staff witness will be addressing the public benefits to resolving issues in a manner that would eliminate potentially lengthy and costly future litigation. In general, Section XIV of the Settlement Agreement addresses the resolution of issues related to the 1999 Settlement Agreement. The Settlement Agreement, of course, must be taken as a whole as to the resolution of the matters it addresses.

Q. What revenue increase did Staff recommend in its direct filing, and how did that relate to the amount of TEP's original requested increase?

A. As described in my direct testimony (filed on 2/29/08), using the cost of service methodology, Staff had recommended a revenue increase of approximately $9.8 million on adjusted fair value rate base. Attachment RCS-2, Schedule A, which was filed with my direct testimony, also showed a jurisdictional revenue deficiency of approximately $9.8 million. Those amounts were comparable to TEP's requested increase of $158.2 million. These increases did not include TEP's proposed TCRAC, which Staff witness John

Antonuk had recommended be rejected. These amounts also did not include the impact of the DSM, Renewables, or PPFAC recovery mechanisms.

Q. Did you assist with the preparation of Settlement Exhibit No. 2?

A. Yes.

Q. What is shown in Settlement Exhibit No. 2?

A. Settlement Exhibit No. 2 presents the Signatories' approach of reconciling the amount of base rate increase that is provided for in the Settlement. It has columns for TEP's original filing, Staff's direct filing, and the Settlement. It shows how the adjustments originally filed by TEP and Staff were ultimately resolved, for Settlement purposes, in deriving the base rate increase of $136.8 million.

Q. Using the information listed on Settlement Exhibit No. 2, have you prepared a reconciliation between the $9.8 million base rate increase shown in Staff's direct filing and the $136.8 million increase shown on Settlement Exhibits Nos. 1 and 2?

A. Yes. The following table summarizes the differences between the $9.8 million base rate increase shown in Staff's direct filing and the $136.8 million increase shown on Settlement Exhibits Nos. 1 and 2:

Reconciliation of Revenue Requirement		ACC Jurisdictional Original Cost	Estimated Revenue Requirement Impact
Rate of Return Difference			
Rate Base per Staff Direct		$ 862,201,951	
ROR Difference		0.1001%	**$ 1,431,848**
Settlement ROR for OCRB x GRCF			
Settlement Rate Base Adjustments - Differences from Staff Direct Filing			
Description			
Springerville Unit 1 - Leasehold Improvements		$ 54,784,951	$ 7,297,978
Accum Depr- Cost of Removal (FAS 143) (Staff B-5)		$ 99,814,938	$ 13,296,484
Accum Depr-Unauthorized Depreciation Rate Changes (Staff B-6)		$ 41,567,880	$ 5,537,314
Other Deferred Credits (B-8 & Partial Staff B-7)		$ 1,039,749	$ 138,506
Customer Care & Billing System (Staff B-9)		$ 4,364,894	$ 581,453
Delayed Unitization		$ 8,043,062	$ 1,071,427
Delayed Unitization - ADIT		$ (114,016)	$ (15,188)
Accumulated Deferred Income Taxes		$ (60,667,582)	$ (8,081,611)
Allowance for Cash Working Capital (Staff B-4/B-4.1)		$ (154,878)	$ (20,632)
ACC Jurisdictional Allocation Computation Errors		$ 9,325,662	$ 1,242,284
Total Adjustments to Staff Rate Base for Settlement Purposes		$ 158,004,659	
OCRB for Settlement Purposes, per Settlement Exhibit No. 1		$ 1,020,206,611	

Reconciliation of Revenue Requirement Continued			
Settlement Net Operating Income Adjustments - Differences from Staff Filing			
Description	Revenue Adjustment	NOI Adjustment	Rev Req Impact
Short-Term Sales Exclusion (Staff C-10)	$ (25,259,000)	$ (15,256,436)	$ 25,322,632
Wholesale Trading Activity (Staff C-11)	$ (171,900)	$ (103,828)	$ 172,334
Service Fees & Late Fees	$ 1,161,265	$ 701,404	$ (1,164,190)
Total Adjustments to Operating Revenues	$ (24,269,635)	$ (14,658,860)	
Adjustments to Operating Expenses:	Expense Adjustment		
Gain on Sale of S02 Allowances (Staff C-12)	$ 8,253,562	$ (4,985,151)	$ 8,274,354
Springerville Unit 1	$ 44,157,287	$ (26,671,002)	$ 44,268,529
Springerville Unit 1 Leasehold Improvements - Depreciation & Property Taxes	$ 7,370,342	$ (4,451,687)	$ 7,388,910
Springerville Unit 1 Delayed Plant - Depreciation & Property Tax	$ 248,856	$ (150,309)	$ 249,483
Payroll Expense	$ 1,389,173	$ (839,060)	$ 1,392,672
Payroll Tax Expense	$ 101,358	$ (61,220)	$ 101,613
CC&B Normalization (Staff C-16)	$ 806,681	$ (487,235)	$ 808,713
Generation Depreciation Rates Adjustment (Staff C-15)	$ 20,000,000	$ (12,080,000)	$ 20,050,384
Springerville Unit 2 Delayed Plant - Depreciation & Property Tax	$ 248,856	$ (150,309)	$ 249,483
Property Tax	$ 110,011	$ (66,447)	$ 110,289
ACC Jurisdictional Allocation Computation Errors	$ 205,847	$ (124,332)	$ 206,366
Subtotal Expense Adjustments Other Than Income Taxes	$ 82,891,974	$ (50,066,752)	
Income Taxes	$ (44,186,045)	$ 1,750,048	$ (2,904,729)
Total Adjustments to Operating Expense	$ 38,705,929		
Total NOI Adjustments for Settlement Purposes		$ (62,975,564)	
Adjusted Net Operating Income per Staff direct filing		$ 62,459,481	
Adjusted Net Operating Income per Settlement		$ (516,083)	
REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED ABOVE			**$ 127,006,706**
Base Rate Revenue Increase per Staff Direct Filing			**$ 9,753,000**
Base Rate Increase per Above Reconciliation			**$ 136,759,706**
Base Rate Revenue Increase per Settlement			$ 136,758,018
Difference, rounding			$ 1,688

Q. Please explain the major impact items.

A. The largest single impact relates to the treatment of Springerville Unit 1. In Staff's direct filing, I had used a $15 per kilowatt-month fixed cost recovery rate. This was based in large part on my understanding at that time of Decision No. 56659 (October 24, 1989), which had required TEP to adjust the revenue requirement effect of Springerville Unit 1 to reflect a $15 per kilowatt-month fixed cost recovery rate that reflected the cost of long-term generation capacity reasonably available at the time of that prior TEP rate case. TEP had proposed to use a much higher monthly fixed cost rate of $25.67 per kW. Both TEP and Staff had excluded Springerville Unit 1 leasehold improvements from rate base. The ratemaking treatment of Springerville Unit 1 was an important subject discussed during my deposition (see Attachment RCS-8). The Settlement negotiations resulted in an agreement to reflect the Springerville Unit 1 leasehold improvements in rate base at cost, and to use TEP's proposed rate of $25.67 per kW. The following reconciling items totaling approximately $59.2 million relate to the ratemaking treatment of Springerville Unit 1 provided for in the Settlement Agreement:

Springerville Unit 1 Related Impacts		**ACC Jurisdictional Original Cost**	**Estimated Revenue Requirement Impact**
Settlement Rate Base Adjustments - Differences from Staff Direct Filing			
Description			
Springerville Unit 1 - Leasehold Improvements		$ 54,784,951	$ 7,297,978
Settlement Net Operating Income Adjustments - Differences from Staff Filing			
Description	Revenue Adjustment	NOI Adjustment	Rev Req Impact
Springerville Unit 1	$ 44,157,287	$ (26,671,002)	$ 44,268,529
Springerville Unit 1 Leasehold Improvements - Depreciation & Property Taxes	$ 7,370,342	$ (4,451,687)	$ 7,388,910
Springerville Unit 1 Delayed Plant - Depreciation & Property Tax	$ 248,856	$ (150,309)	$ 249,483
Approximate impact on Staff direct filing from Settlement Agreement related to Springerville Unit 1			$ 59,204,900

Q. Did another significant impact relate to Accumulated Depreciation and the depreciation rates that TEP had been applying?

A. Yes. TEP had formed an accounting interpretation that its generation had been deregulated. Based on that accounting interpretation, TEP had implemented certain changes that had a major impact on the test year Accumulated Depreciation on TEP's generation plant through the end of the test year. On January 1, 2003, TEP recorded entries related to the implementation of Statement of Financial Accounting Standards ("FAS") No. 143, entitled "Accounting for Asset Retirement Obligations." TEP's adoption of FAS 143 reduced Accumulated Depreciation by $112.8 million to remove previously recorded Accumulated Depreciation that it had collected for estimated future cost of removal through its rates through the end of 2002. TEP also reduced subsequent accruals of depreciation expense because TEP removed the cost of removal component from its depreciation rates for generation. TEP's treatment of these depreciation issues was significantly different than that of other major Arizona electric utilities, such as Arizona Public Service Company ("APS"). Additionally, as described in my direct testimony, TEP implemented other depreciation rate changes without Commission authorization which have affected in a material manner the amount of TEP's recorded Accumulated Depreciation on generation plant as of December 31, 2006, the end of the test year. My direct testimony, filed on February 29, 2008, discussed these rate base issues related to Accumulated Depreciation at pages 31-42. Because of concerns regarding these depreciation issues, Staff's direct filing had reflected two adjustments (Staff Rate Base Adjustments B-5 and B-6) to reduce TEP's proposed rate base by approximately $141.4 million. There was a related adjustment to depreciation expense (Staff Adjustment C-15).

As a result of Settlement discussions, a compromise was reached that resulted in eliminating those two rate base adjustments from the derivation of the Settlement rate base, and addressing, in an alternative manner, the concerns that TEP's Accumulated Depreciation balance was understated due to the factors described in my direct testimony.

Q. Please describe the alternative manner in which the Settlement Agreement addresses Staff's concerns.

A. As noted above, one of Staff's concerns was that TEP's balance of Accumulated Depreciation had been understated. Rather than addressing this concerning by an adjustment to test year rate base, the Settlement Agreement addresses this concern ***prospectively*** by providing for a rate case moratorium (in Section X) and for depreciation rates (in Section V) for TEP's generating plant that include $21.6 million per year on an ACC jurisdictional basis for cost of removal. Consequently, during the rate moratorium period, this provision will provide future ratepayer benefit by building up the balance of Accumulated Depreciation related to accruals for cost of removal on TEP's generating plant in a manner that may not have been achievable without the Settlement. Addressing this matter by a prospectively-applied remedy, as provided in the Settlement, also was responsive to TEP's desire to avoid write-offs on its financial statements and/or potentially having to re-state prior years' financial statements.

Q. What items on the reconciliation relate to the compromise on Accumulated Depreciation and prospectively-applied depreciation rates for generation plant which include the extra accruals for cost of removal?

A. The following items, having a revenue requirement impact of approximately $40.1 million, relate to this compromise (and a related correction for a jurisdictional allocation error):

Reconciliation of Revenue Requirement		ACC Jurisdictional Original Cost	Estimated Revenue Requirement Impact
Settlement Rate Base Adjustments - Differences from Staff Direct Filing			
Description			
Accum Depr- Cost of Removal (FAS 143) (Staff B-5)		$ 99,814,938	$ 13,296,484
Accum Depr-Unauthorized Depreciation Rate Changes (Staff B-6)		$ 41,567,880	$ 5,537,314
ACC Jurisdictional Allocation Computation Errors		$ 9,325,662	$ 1,242,284
Settlement Net Operating Income Adjustments - Differences from Staff Filing			
Description	Revenue Adjustment	NOI Adjustment	Rev Req Impact
Generation Depreciation Rates Adjustment (Staff C-15)	$ 20,000,000	$ (12,080,000)	$ 20,050,384
Approximate impact on Staff direct filing from Settlement on Accum Depreciation related issues			$ 40,126,466

Q. Why was $20 million of additional depreciation expense provided for in the Settlement Agreement?

A. This was provided for only in the context of the Settlement as an alternative means of addressing Staff's concerns about the level of Accumulated Depreciation. As noted above, this provision is designed to achieve a larger ***prospective*** build-up in TEP's Accumulated Depreciation balance during the rate moratorium period.

Q. Do you view this component of the Settlement Agreement as having being beneficial to ratepayers?

A. Yes. Accumulated Depreciation is a deduction from rate base. Providing for the prospective build-up of the Accumulated Depreciation balance related to TEP's generation plant during the rate moratorium period in the manner achieved in the Settlement has more benefit to ratepayers than would have, for example, reflecting a higher return on equity, or using TEP's proposed capital structure, for Settlement purposes or by reflecting in the Settlement revenue requirement details compromises on other expense adjustment issues where differences remained between TEP and Staff. The build-up of Accumulated Depreciation during the rate moratorium period related to the prospective additional accruals for cost of removal on TEP's generating plant will result in rate base being lower than it would otherwise be, in TEP's future rate cases.

Q. How important was reaching the compromise on Accumulated Depreciation and related issues to the ultimate Settlement Agreement?

A. It was very important. The willingness of the parties to give serious consideration to their respective positions and to reach the compromise provided for in the Settlement Agreement on these issues was one critical factor which has allowed the parties to reach the Settlement. I believe that Staff's litigation position regarding the depreciation issues is well-reasoned and appropriate, but I also recognize that TEP's position might be regarded as reasonable by some. The compromise reached in the Settlement Agreement resolves a very contentious issue and, at the same time, provides a prospective benefit to ratepayers by building up the balance of Accumulated Depreciation related to accruals for cost of removal in a manner that may not have been achievable without the Settlement.

Q. Please explain the Settlement treatment of the Short-Term Sales Exclusion and the Wholesale Trading Activity.

A. The Settlement Agreement treats Short-Term Sales Revenue (Staff adjustment C-10) and ten percent (10 percent) of the positive annual margins realized by TEP on Wholesale Trading Activity (Staff adjustment C-11) as credits to PPFAC costs. As described in my direct testimony, Staff's derivation of the proposed revenue increase of approximately $9.8 million had treated these items as offsets to the base rate revenue increase, with annual fluctuations above or below the amounts included in base rates reflected as adjustments to PPFAC-includable costs. Addressing these items fully in the PPFAC is a reasonable alternative, and should have similar ultimate rate impacts.

Q. Please explain the Settlement treatment of Service Fees and Late Fees.

A. The Settlement reflects TEP's updated and corrected amounts for service fees and late fees. Acceptance of these corrected amounts reduced Staff's originally filed (and TEP's originally filed) revenue requirement by approximately $1.2 million, as shown on Attachment RCS-7.

Q. Please explain the Settlement treatment of the Gain on Sale of SO2 Allowances.

A. Staff's derivation of the proposed revenue increase of approximately $9.8 million had reflected a normalized amount of Gains on the Sale of SO2 Allowances as an offset to the test year expenses (which in turn reduced the amount of the base rate revenue increase). Similar to the treatment of Short-Term Sales Revenue, annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO2 Allowances would have been reflected as adjustments to PPFAC-includable costs. The Settlement provides for 50 percent of the annual Gains on the Sale of SO2 Allowances to be credited in the PPFAC against PPFAC includable costs. The 50 percent crediting reflects a compromise by the parties reached through Settlement negotiations. Crediting such gains through the PPFAC is appropriate and reasonable because emission allowances are closely related to the amount of coal burned at TEP's generating plants.

Q. Were other differences between TEP's and Staff's recommendations that affected the revenue requirement compromised in a manner that you believe was reasonable?

A. Yes.

III. RATEMAKING TREATMENT OF TEP'S GENERATION ASSETS AND FUEL COSTS

Q. What is provided for in the Settlement Agreement concerning TEP's generation assets?

A. Section III of the Settlement Agreement resolves the disputes between the parties concerning the ratemaking treatment of TEP's generation assets. Paragraph 3.1 of the Settlement Agreement provides, for ratemaking purposes, that Springerville Unit 1 and the Luna Generating Station shall be included in TEP's rate base at their respective original costs. Moreover, all other generation assets acquired by TEP after December 31, 2006 but before December 31, 2012, shall be included in TEP's rate base at their respective original costs, subject to the Commission's subsequent regulatory and ratemaking review and approval.

Paragraphs 3.2 and 3.3 address the specific ratemaking treatment of Springerville Unit 1 and Luna, respectively.

Q. What base cost of fuel and purchased power is provided for in the Settlement Agreement?

A. As described in paragraph 3.4, the Settlement Agreement provides for a base cost of fuel and purchased power of $0.028896 per kWh.

Q. Does the Settlement Agreement include a calculation showing how that amount was derived?

A. Yes. Settlement Exhibit No. 4, attached to the Settlement Agreement, shows, by FERC account, the adjusted expenses for PPFAC-includable fuel and purchased power expenses, and how the $0.028896 per kWh was derived. Settlement Exhibit No. 4 also shows, for comparison purposes, the expenses used to derive the $0.033000 per kWh base cost of fuel and purchased power per TEP's original filing in this proceeding.

IV. COST OF CAPITAL

Q. What cost of capital is provided for in the Settlement Agreement?

A. The cost of capital is addressed in Section IV of the Settlement Agreement. The cost of capital on original cost rate base provided for in the Settlement is summarized in the following table:

Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Settlement				
Long-Term Debt	$ 586,619	57.50%	6.38%	3.67%
Common Stock Equity	$ 433,588	42.50%	10.250%	4.36%
Total Capital supporting OCRB	$ 1,020,207	100.00%		8.03%

Q. Have you prepared an additional calculation to derive the fair value rate of return?

A. Yes. I prepared the additional calculation shown below to derive the 5.64 percent fair value rate of return ("FVROR") shown in Attachment RCS-8. This calculation is consistent with the "Option 1" method of deriving the FVROR that was presented in Attachment RCS-2 filed with my direct testimony:

Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Fair Value Rate of Return for Fair Value Rate Base				
Long-Term Debt	$ 586,619	40.41%	6.38%	2.58%
Common Stock Equity	$ 433,588	29.87%	10.250%	3.06%
Capital financing OCRB	$ 1,020,207			
Appreciation above OCRB not recognized on utility's books	$ 431,351	29.72%	0% [a]	0.00%
Total capital supporting FVRB	$ 1,451,558	100.00%		5.64%
Fair Value Rate of Return for Fair Value Rate Base				5.64%

Notes and Source

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

Q. Does the Settlement provide for a specific method to derive the FVROR?

A. No. The Settlement Agreement, in paragraph 4.3 and on Settlement Exhibit 1, provides for the FVROR of 5.64 percent, but does not specify a methodology for deriving that figure.

V. DEPRECIATION AND COST OF REMOVAL

Q. What does the Settlement Agreement provide for depreciation rates?

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that TEP shall use the depreciation rates contained in Settlement Exhibit No. 5.

Q. How were those depreciation rates derived?

A. In general, the depreciation rates for Distribution and General Plant are consistent with TEP's originally filed depreciation study. Additionally, for generation plant, the remaining lives and cost recovery rates are consistent with TEP's revised depreciation study that was filed with TEP witness Kissinger's rebuttal testimony. As a result of Settlement negotiations, an additional provision for increased accruals for cost of removal on TEP's generation plant has been included in the depreciation rates provided for in the Settlement Agreement. This provision is closely related to the compromises the parties reached concerning the amount of Accumulated Depreciation reflected in rate base. It provides for additional build-up for TEP's Accumulated Depreciation balance related to cost-of-removal accruals on generation plant during the rate moratorium period. As such, the additional depreciation accruals provided for in Settlement Paragraph 5.2 contain an element of future benefit to TEP's ratepayers.

Q. Why does TEP's Luna Generating Station have separately identified depreciation rates, as specified in Settlement Paragraph 5.2, and listed on Settlement Exhibit No. 5?

A. Actually, each of TEP's generating units, including Luna, have separately identified depreciation rates on Settlement Exhibit No. 5. A detailed calculation process was used to spread the $21.6 million annual accrual for cost of removal among TEP's generating plants in deriving the depreciation rates shown on Settlement Exhibit No. 5. TEP had originally proposed to treat the Luna Generating Station, for ratemaking purposes, at a "market" based amount, rather than at original cost. Accordingly, TEP had not included Luna in its originally proposed depreciation rates. The Settlement Agreement provides that the Luna Generating Station is being treated on a cost basis for ratemaking purposes. Consequently, depreciation rates for Luna needed to be specified. The Luna depreciation rates were added to the generation depreciation rates after the $21.6 million Settlement amount annual accrual for cost of removal had been spread to TEP's other generating units. Consequently, Settlement Paragraph 5.2 indicates that none of that $21.6 million Settlement amount annual accrual for cost of removal was allocated to Luna.

VI. IMPLEMENTATION COST RECOVERY ASSET

Q. How does the Settlement Agreement treat the Implementation Cost Recovery Asset?

A. Section VI of the Settlement Agreement addresses the ratemaking treatment of the Implementation Cost Recovery Asset ("ICRA"). Consistent with Staff's recommendation, $14.2 million is included in rate base. That amount is amortized over a four-year period, which is also consistent with Staff's recommendation. Amounts in excess of the $14.2 million that were originally requested by TEP have been removed from rate base and from amortization expense.

Additionally, Paragraph 6.2 of the Settlement Agreement specifies that the ICRA shall not be included in rate base or as an amortization expense in TEP's next rate case. The timing of when TEP can file its next rate case is addressed in Section X of the Settlement Agreement, which provides for a rate case moratorium.

VII. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. How does the Settlement Agreement provide for a PPFAC?

A. Section VII of the Settlement Agreement addresses the provisions of the PPFAC that have been agreed to by the parties through the process of negotiation. The plan of administration for the PPFAC is provided in Settlement Exhibit No. 6.

Q. Is it reasonable to provide for the recovery of TEP's fuel and purchased power costs through a PPFAC?

A. Yes. TEP does not currently have a PPFAC. However, TEP does have significant fuel and purchased power costs. For the reasons described in my direct testimony, it is reasonable to provide for the recovery of TEP's fuel and purchased power costs through a PPFAC.

XV. FIXED CTC TRUE-UP REVENUES

Q. What information are you providing concerning Fixed CTC True-Up Revenue?

A. Other Staff witnesses are presenting Staff's position concerning the disposition of Fixed CTC True-Up Revenue. I have been asked to provide the estimated amounts of such revenue. Based on the information provided by TEP in response to Staff data request LA-25-1, I have summarized these estimated amounts, by month and cumulatively, in the following table:

Estimated Amounts of Fixed CTC True-Up Revenue
(Thousands of Dollars)

Month	Year	Revenue Amount	Cumulative Amount
May	2008	$ 7,117	$ 7,117
June	2008	$ 9,711	$ 16,828
July	2008	$ 10,731	$ 27,559
August	2008	$ 10,511	$ 38,070
September	2008	$ 9,027	$ 47,097
October	2008	$ 7,301	$ 54,398
November	2008	$ 6,323	$ 60,721
December	2008	$ 7,189	$ 67,910
Total		$ 67,910	

Source: TEP's response to Staff data request LA-25-1

XIX. FUEL AUDIT

Q. What does the Settlement provide for TEP's implementation of the fuel audit recommendations set forth in Staff's direct testimony?

A. Section XIX of the Settlement Agreement addresses the fuel audit recommendations. TEP has agreed to implement Staff's recommendations. TEP need not complete its implementation of such recommendations prior to implementing the PPFAC. Section XIX provides that TEP should file an implementation plan within 90 days of the effective date of the Commission's order approving the Settlement Agreement.

Q. Does this conclude your Testimony?

A. Yes, it does.

Reconciliation of Revenue Requirement		ACC Jurisdictional Original Cost	Conversion Factor	Estimated Revenue Requirement Impact	Comment
Rate of Return Difference					
Rate Base per Staff Direct		$ 862,201,951			Reflects capital structure compromise 57.5/42.5 debt/equity
ROR Difference		0.1001%	1.6598	$ **1,431,848**	Staff direct used 7.93%; Settlement uses 8.03%
					Settlement incorporates Staff ROE of 10.25%
Settlement ROR for OCRB x GRCF			8.03%		
Settlement Rate Base Adjustments - Differences from Staff Direct Filing			0.133211359		
Description		Rate Base Adj.			
Implementation Cost Regulatory Asset (Staff B-3)		$ -	0.133211359	$ -	no difference, reflects agreement with Staff's direct filing
Springerville Unit 1 - Leasehold Improvements		$ 54,784,951	0.133211359	$ 7,297,978	under consideration for adjustment when sch was suspended
Renewable Resources		$ -	0.133211359	$ -	no difference, reflects agreement with Staff's direct filing
Luna Plant (Staff B-2)		$ -	0.133211359	$ -	no difference, reflects agreement with Staff's direct filing
Accum Depr- Cost of Removal (FAS 143) (Staff B-5)		$ 99,814,938	0.133211359	$ 13,296,484	reflects compromise for settlement purposes only
Accum Depr-Unauthorized Depreciation Rate Changes (Staff B-6)		$ 41,567,880	0.133211359	$ 5,537,314	reflects compromise for settlement purposes only
Other Deferred Credits (B-8 & Partial Staff B-7)		$ 1,039,749	0.133211359	$ 138,506	relatively minor impact, reflects settlement compromise
Customer Care & Billing System (Staff B-9)		$ 4,364,894	0.133211359	$ 581,453	under consideration for adjustment when sch was suspended
Delayed Unitization		$ 8,043,062	0.133211359	$ 1,071,427	under consideration for adjustment when sch was suspended
Delayed Unitization - ADIT		$ (114,016)	0.133211359	$ (15,188)	under consideration for adjustment when sch was suspended
Accumulated Deferred Income Taxes		$ (60,667,582)	0.133211359	$ (8,081,611)	under consideration for adjustment when sch was suspended
Allowance for Cash Working Capital (Staff B-4/B-4.1)		$ (154,878)	0.133211359	$ (20,632)	fall out number, dependent upon other adjustments
Allowance for Working Capital (Staff B-4.2)		$ -	0.133211359	$ -	no difference, reflects agreement with Staff's direct filing
ACC Jurisdictional Allocation Computation Errors		$ 9,325,662	0.133211359	$ 1,242,284	error corrections
Total Adjustments to Staff Rate Base for Settlement Purposes		$ 158,004,659			
OCRB for Settlement Purposes, per above		$1,020,206,611			
Rounding		$ 0			
OCRB for Settlement Purposes, per Settlement Exhibit No. 1		$1,020,206,611			
Settlement Net Operating Income Adjustments - Differences from Staff Direct Filing					
Description	Revenue Adjustment	NOI Adjustment	GRCF		
Stranded Costs & Fixed CTC	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
SlimFast Contract Termination Fee	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Customer Annualization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Weather Normalization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Short-Term Sales Exclusion (Staff C-10)	$ (25,259,000)	$ (15,256,436)	1.6598	$ 25,322,632	reflects compromise for settlement; reflected in PPFAC
Wholesale Trading Activity (Staff C-11)	$ (171,900)	$ (103,828)	1.6598	$ 172,334	reflects compromise for settlement; reflected in PPFAC
Heavy Equipment - Operating Lease	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Springerville Unit 1	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Renewable Resources	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Service Fees & Late Fees	$ 1,161,265	$ 701,404	1.6598	$ (1,164,190)	correction to originally filed amount
Lime Usage Costs	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Tri-State Fuel Oil Sales	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Building Usage Allocations	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Springerville Unit 3	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Total Adjustments to Operating Revenues	$ (24,269,635)	$ (14,658,860)			

Reconciliation of Revenue Requirement		ACC Jurisdictional Original Cost	Conversion Factor	Estimated Revenue Requirement Impact	Comment
Adjustments to Operating Expenses:	Expense Adjustment				
Implementation Cost Regulatory Asset (Staff C-20)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Stranded Costs & Fixed CTC	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Customer Annualization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Weather Normalization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Unit Availability Normalization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Short-Term Sales Exclusion	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Wholesale Trading Activity	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Test Power Exclusion	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Sundt Coal Contract	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Navajo Coal Contract	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
San Juan Coal (Staff C-4)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
PPFAC Adjustment (Staff C-19)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Gain on Sale of S02 Allowances (Staff C-12)	$ 8,253,562	$ (4,985,151)	1.6598	$ 8,274,354	reflects compromise for settlement; 50% of gains w/b in PPFAC
Generating Facilities - Operating Lease	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Heavy Equipment - Operating Lease	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Railcar - Operating Lease	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Springerville Unit 1	$ 44,157,287	$ (26,671,002)	1.6598	$ 44,268,529	under consideration for adjustment when sch was suspended
Springerville Unit 1 Leasehold Improvements - Depreciation & Property Taxes	$ 7,370,342	$ (4,451,687)	1.6598	$ 7,388,910	under consideration for adjustment when sch was suspended
Springerville Unit 1 Delayed Plant - Depreciation & Property Tax	$ 248,856	$ (150,309)	1.6598	$ 249,483	under consideration for adjustment when sch was suspended
Luna O&M (Staff C-2/C-3)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Plant Overhaul & Outage Normalization	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Renewable Resources	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Payroll Expense	$ 1,389,173	$ (839,060)	1.6598	$ 1,392,672	under consideration for adjustment when sch was suspended
Payroll Tax Expense	$ 101,358	$ (61,220)	1.6598	$ 101,613	under consideration for adjustment when sch was suspended
Pension & Benefits	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Post Retirement Medical	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Incentive Compensation (Staff C-7)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Rate Case Expense	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Membership Dues (Staff C-6)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Advertising & Sponsorship	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Outside Services	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
CC&B Normalization (Staff C-16)	$ 806,681	$ (487,235)	1.6598	$ 808,713	under consideration for adjustment when sch was suspended
Out of Period Expenses	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Lime Usage Costs	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Tri-State Fuel Oil Sales	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Bad Debt Expense (Staff C-5)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Capital Cost Allocations	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Corporate Cost Allocations	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
SERP (Staff C-8)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Worker's Compensation (Staff C-9)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Legal Expense - Motion to Amend (Staff C-21)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing

Reconciliation of Revenue Requirement		ACC Jurisdictional Original Cost	Conversion Factor	Estimated Revenue Requirement Impact	Comment
Legal Expense - California Proceedings (Staff C-22)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Generation Depreciation Rates Adjustment (Staff C-15)	$ 20,000,000	$ (12,080,000)	1.6598	$ 20,050,384	reflects compromise for settlement purposes only
Markup Above Cost - Affiliate Charges SES (Staff C-17)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Normalize Affiliate Charges to TEP (Staff C-18)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Postage Expense (Staff C-23)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
West Connect Charges in ICRA (Staff C-24)	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
OATT	$ -	$ -	1.6598	$ -	no difference, reflects agreement with Staff's direct filing
Springerville Unit 2 Delayed Plant - Depreciation & Property Tax	$ 248,856	$ (150,309)	1.6598	$ 249,483	under consideration for adjustment when sch was suspended
Depreciation & Amort Expense Annualization	$ -	$ -	1.6598	$ -	no difference on this line, but see $10M depreciation adj above
Property Tax	$ 110,011	$ (66,447)	1.6598	$ 110,289	under consideration for adjustment when sch was suspended
ACC Jurisdictional Allocation Computation Errors	$ 205,847	$ (124,332)	1.6598	$ 206,366	error corrections
Subtotal Expense Adjustments Other Than Income Taxes	$ 82,891,974	$ (50,066,752)			
Income Taxes	$ (44,186,045)	$ 1,750,048	1.6598	$ (2,904,729)	result of other adjustments
Total Adjustments to Operating Expense	$ 38,705,929				
Total NOI Adjustments for Settlement Purposes		$ (62,975,564)			
Adjusted Net Operating Income per Staff direct filing		$ 62,459,481			
Adjusted Net Operating Income per Settlement		$ (516,083)			
REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED ABOVE				**$ 127,006,706**	
Base Rate Revenue Increase per Staff Direct Filing				**$ 9,753,000**	
Base Rate Increase per Above Reconciliation				**$ 136,759,706**	
Base Rate Revenue Increase per Settlement				**$ 136,758,018**	
Difference, rounding				$ 1,688	

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DEPOSITION OF RALPH C. SMITH

Livonia, Michigan
March 10, 2008

ARIZONA REPORTING SERVICE, INC.
Court Reporting
Suite 502
2200 North Central Avenue
Phoenix, Arizona 85004-1481

By: MICHELE E. BALMER
Certified Reporter
Certificate No. 50489

Prepared for:

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DEPOSITION OF RALPH C. SMITH was taken on March 10, 2008, commencing at 9:30 a.m. at the offices of LARKIN & ASSOCIATES, PLLC, 15728 Farmington Road, Livonia, Michigan, before MICHELE E. BALMER, Certified Reporter No. 50489 for the State of Arizona.

APPEARANCES:

For the Arizona Corporation Commission:
Ms. Robin R. Mitchell
Staff Attorney, Legal Division
1200 West Washington Street
Phoenix, Arizona 85007

For Tucson Electric Power Company:
ROSHKA, DEWULF & PATTEN, P.L.C.
By Mr. Michael W. Patten
One Arizona Center
400 East Van Buren, Suite 800
Phoenix, Arizona 85004
- and -
TUCSON ELECTRIC POWER COMPANY
By Ms. Michelle Livengood
One South Church Avenue, Suite 200
Tucson, Arizona 85701

ALSO PRESENT:
Mr. Dallas Dukes, Tucson Electric Power Company
Mr. Tim Zeldenrust, Huron Consulting Group

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(Exhibit No. 1 was marked for identification.)

RALPH C. SMITH,
called as a witness, having been first duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

EXAMINATION

Q. (BY MR. PATTEN) Good morning, Mr. Smith.
A. Good morning.
Q. A little different than a hearing. I assume you have been deposed a few times before?
A. Yes.
Q. Just some ground rules. If I ask a question that you don't understand, let me know. And if you don't, I will try to rephrase it. And I'll assume that if you answer the question you have understood the question.
Is that fair enough?
A. Sure.
Q. Let's see. Just some background. Who is your primary contact at the ACC on this matter?
A. For this case, Alexander Igwe.
Q. Okay. Who else did you interact with at the Commission on this particular matter?

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A. Quite a few people.
Q. Who would they be?
A. Oh, people on the legal staff. I think there was some changeover in attorneys during the course of the case. Chris Kempley, Janet Wagner. I don't remember if Keith Layton was involved in this one or if that was one of the other cases. Ernest Johnson, Elijah Abinah. A couple of the other people in the legal department. I've got a contact list if that would help.
Q. I'm just curious what comes to the top of your mind in terms of who your primary contacts were with.
A. The primary contact was Alexander, but --
Q. How would you communicate with him? By phone? By e-mail?
A. By phone usually. Occasionally, I mean, when we sent drafts, obviously we e-mailed, you know, the drafts. I'm trying to think if we FedEx'd anything. I think we had to FedEx the Pricewaterhouse letter.
Q. Okay. Primarily by phone with Alex or primarily by e-mail?
A. Primarily by phone. But when we were transmitting the documents, the documents were transmitted by e-mail.
Q. Okay. In your activity in this docket, did you perform any litigation risk analysis with respect to the

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1999 settlement?
A. I wouldn't -- no, I wouldn't call it litigation risk analysis. I mean, obviously we had discussions of the settlement and what the implications were. And another consultant for Staff, John Antonuk, was primarily focusing on that area.
Q. And who did you have discussions with regarding the 1999 settlement agreement?
A. I'm not sure I can recall everybody. I think there were a couple of conference calls where the Staff team, all of the people I just mentioned and probably some others were involved, and then John Antonuk, and then I think there was Stephanie from his office.
Occasionally there was some other consultants on the phone. Dave Parcell, I think, was on some of the calls. I don't remember which ones. Emily Medine and some people from her office were on a couple of the calls.
I think there was some other people from Technical Associates that were doing some engineering stuff. I think there was some people on the engineering Staff of the Commission.
Q. Okay. Were any of those discussions used as the basis of your recommendations in this case?
MS. MITCHELL: Mike, I would like to just put -- to the extent that that requires any answer that may touch

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on attorney-client privilege, I would like to lodge an objection to that.
MR. PATTEN: Attorney-client privilege, that's fine. I'm asking the basis of his expert opinions and recommendations so --
THE WITNESS: I guess John Antonuk's ultimate conclusion that the cost of service methodology should be used obviously impacted what I was doing.
Q. (BY MR. PATTEN) Anything else?
A. And I think he also recommended that the 788 million transition cost regulatory asset be rejected. That wasn't included in the company's base rate revenue requirement. The company had set that up as a separate surcharge, so I didn't have to make a separate adjustment for that.
Q. Any other impact of the 1999 settlement agreement from those conversations affect the basis for your recommendations?
A. Well, I think there's like a backdrop to the entire case where TEP apparently thinks that their generation has been deregulated, and nobody else seems to share that opinion. So I think that's a major difference running throughout the case. And the Staff's position essentially reflects the view that TEP's generation has not been deregulated. It's still under the regulation of

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the Commission.
Q. Okay.
A. I think that that's probably one of the interpretations of what has been left in the aftermath of that 1999 settlement and the subsequent events. I think John Antonuk's testimony goes into that, you know, in a lot more detail. He was the witness responsible for that analysis, not me.
Q. Okay. Did you yourself do any interpretation of the 1999 settlement agreement in reaching your recommendations in this case?
A. In reaching my recommendations?
Q. Yeah.
A. I read a whole bunch of orders, including the 1999 settlement, some previous to that, some subsequent to that. And I think, you know, one of the functions or roles that I had in addition to doing my own area was just act as a reasonableness check on some of the other Staff conclusions, including John Antonuk's.
So if I had seen anything in his analysis or conclusions that I thought wasn't supported by a reasonable analysis of the facts, I think one of my functions would be to let Staff know about that. But as it turns out, I think his analysis is okay.
Q. Did you have any questions about his analysis?

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A. Any questions?
Q. I guess of the 1999 settlement agreement and its impact.
A. I'm trying to think. There was some pretty lengthy discussions about that. I mean, it is, you know, one of the underlying themes of the case. I don't recall if I had any questions or not.
Q. You didn't participate in any of the electric deregulation dockets in Arizona, did you?
A. Yes, I did.
Q. What was your role in those? Just could you describe an overview of what your role was?
A. Yeah. Our client was the Federal Executive Agencies at that point, and we had just participated in the California deregulation. We were participating pretty heavily in that, and I think I filed testimony or comments. I remember one of the issues was securitization. I kind of vaguely remember addressing that.
Q. Do you recall the time frame that you were participating? Or was it you or someone else from your firm?
A. It was me.
Q. Do you recall the time frame?
A. Well, it was that whole time frame before the

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California meltdown. '99 through the end of 2000 was where the California energy crisis reached its peak, and it would have been prior to that.
Q. Okay. Did you participate in the industry working groups that led to the adoption of the Retail Electric Competition Rules in Arizona?
A. I'm trying to think if I participated in that or not. We were doing kind of like on a contract with the Federal Executive Agencies concerning some of the deregulation activities in the western states. And I don't remember if we were involved in workshops or not. I know we were involved in workshops in California. I don't remember if we were in Arizona.
Q. Okay. And what was the general focus of the Federal Executive Agencies that you participated in?
A. My focus was to look at utility estimates of stranded cost, mainly, and the ratemaking impacts.
Q. Did you participate in the generic stranded cost dockets in front of the Commission?
A. I participated in one docket. And like I said, the issue that stands out was there was some securitization issue. I think there was some issue with stranded costs. I don't remember the docket number or anything.
Q. Okay. You don't recall whether it was testimony

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or comments that you filed in that?
A. I think in Arizona it was actual testimony, because I remember being at the hearing.
Q. Including presenting evidence as a witness there?
A. Yes. I remember RUCO asking me some questions about securitization. I think they were not in favor of it, and I thought there might be some cost saving benefits.
Q. Okay. Did you participate in the negotiation of the 1999 settlement agreement with TEP?
A. No.
Q. Not on behalf of the Federal Executive Agencies?
A. If they did those negotiations, I was not on the phone.
Q. At all?
A. No.
Q. So you weren't – you have no knowledge of the negotiation that led up to the 1999 settlement agreement?
A. Just from what I've read. I wasn't directly involved in those.
Q. In reaching your recommendations in this case, did you do any analysis or interpretation of the Arizona Retail Electric Competition Rules?
A. I read some of the materials. Again, that was – those types of interpretations were the issue that John

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Antonuk of Liberty Consulting was focusing on.
Q. So to the extent that you might have relied on the Retail Electric Competition Rules in Arizona, would that be set forth in your testimony?
A. Probably not, because I didn't really address those competition rules.
Q. But if the rules were a basis of one of your recommendations, would you have identified them in your testimony?
A. Well, I mean, my testimony addresses basically three major areas: The revenue requirement calculation, which includes adjustments to rate base and operating income; it includes the PPFAC; and it includes a discussion of depreciation issues.
The issue of the interpretation of the Act and the 1999 settlement, the subsequent events and decisions and the impact of those events on this case in terms of, you know, which ratemaking methodology should be used, and some of the other company claims, was being addressed by another witness and that witness is John Antonuk.
Q. Okay.
A. And his firm was responsible for analyzing all of that stuff.
Q. So just to be clear, your testimony, you do not do any -- you're not testifying as to the 1999 settlement

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agreement and its impact; correct?
A. Right.
Q. And you're not testifying with respect to the Retail Electric Competition Rules and their impact; correct?
A. I don't believe that's in my testimony.
Q. Okay. And you are not the witness that is testifying with respect to the three methodologies proposed by TEP; correct?
A. Well, I am testifying on the fact that Staff used the cost of service methodology --
Q. But --
A. -- and which Staff has reflected adjustments under the cost of service methodology. In terms of the choice between the three, that would be John Antonuk.
Q. And you have not expressed any opinion in your testimony or have not been asked to testify as to which is the preferable methodology. Is that a correct understanding?
A. Well, I don't think I -- I mean, I don't think I state that in my testimony, but, I mean, there were substantial vetting discussions. And if anybody thought that -- on the Staff team thought that the cost of service methodology wasn't the proper one, there probably would have been some modification. But I think everybody on the

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Staff team, at least to my knowledge, from what they've seen believes that that's the correct methodology. But the witness that's addressing that in Staff's direct testimony is John Antonuk.
Q. Okay. Who made the final decision on the recommendation that the cost of service methodology was the correct methodology?
A. Who made that recommendation?
Q. Who made the final decision on that recommendation?
A. Well, the recommendation is in John Antonuk's testimony. And I think, eventually, my impression was that everybody on the Staff team concluded that that was the correct and accurate decision.
And any question about who was the ultimate, you know, decision-maker on Staff, I guess ultimately that's Ernest Johnson, the Director. But Ernest is a pretty reasonable guy and he, you know, he listens to people, listens to the, you know, the discussion. So I think if, you know, if John's testimony hadn't been as strong as it is, I think, you know, maybe the decision might have been different.
But as we went into the case, I mean, the directive was to, you know, as I understood it, was for Liberty to analyze the methodologies and come up with

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their recommendation as to which was the appropriate one.
Q. Okay.
A. But their ideas were, you know, bounced around between a lot of other folks, so --
Q. Did you have any input into those ideas or not?
A. I was kind of supposed to be available to them if they had some accounting question, to help them work through the accounting or interpretation of the accounting.
Q. And did they have accounting questions?
A. They did have some, yeah.
Q. Do you recall what those questions were?
A. I think they had some questions about the historical earnings. And I know that I had asked some questions in one of our data request sets to try to get some additional information so I could understand it better and hopefully give them some valuable feedback.
And one of the questions, I don't remember which set it was in, but asked for historical earnings. And then I know when that came in I forwarded that on to Liberty.
Q. Do you recall anything else that you provided them with respect to accounting questions?
A. I know we had some discussions about the adoption by the company of FAS 143 and how that was implemented.

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That was primarily my area. But to the extent that it affected historical earnings, I think we had a couple of discussions where I explained the company's financial reporting for that item.
Q. Okay. Anything beyond those two items?
A. There probably was, but I think those are the ones that stand out as I'm thinking about it right now.
Q. Can you recall the other ones just in general?
A. Not as I'm sitting here. I think those were the main ones, but there probably were some others.
Q. And with respect to the FAS 143 discussions, could you go into a little more detail about the nature of those discussions with John Antonuk or his office?
A. Well, I think they were looking at historical earnings. And when the company booked the 143 adjustment, they removed a large amount out of accumulated depreciation and treated it as an extraordinary gain, extraordinary income in their financial statements. And so that affected the reported earnings for that year.
Q. Okay. And do you know how that affected Mr. Antonuk's analysis?
A. I think he was looking at earnings, the ordinary earnings line before that item. I believe I may have cautioned him about not focusing on the rate of return that included that extraordinary item.

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Q. Okay. Anything else with respect to FAS 143 that you recall discussing with Mr. Antonuk?

A. Well, when I discussed with the Staff team all of the adjustments we were making, at least the larger ones, you know, he was on those calls. I don't recall him asking any specific questions about it.

And I know one of the things that he was asking about was like what was our final revenue requirement number, so I tried to keep him updated on that.

Q. That's with respect to your recommendation under the cost of service analysis you were doing?

A. Right. My recommendation, which also reflects the recommendations of other Staff witnesses. Dave Parcell addresses the rate of return, and Emily Medine addressed some issues related to coal and fuel procurement, purchased power.

Q. Okay. With respect to those witnesses, did you just rely on their testimony? You didn't do any independent analysis on the issues that they addressed?

A. No. I always try to evaluate, when I'm given something, is it reasonable or not? And if I see some aspect of it that's not reasonable, I feed it back to them and, you know, we need to talk it through.

Q. With respect to Ms. Medine's testimony, did you identify anything that she was recommending that you felt

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to be unreasonable?

A. Not in her final testimony.

Q. Prior to her final testimony?

A. Prior to her final testimony, there was some discussions and some things got revised.

Q. What were those things?

A. I think that since the attorneys were on the calls when those things were being discussed, that may get into attorney-client privilege.

MS. MITCHELL: Thank you for making that objection for me. Because I wasn't on those calls, but it was probably Janet or Chris.

MR. PATTEN: I mean, I don't know that it's attorney-client privilege if they just happened to be sitting there.

MS. MITCHELL: But they could have --

Q. (BY MR. PATTEN) Do you know whether those affected Ms. Medine's recommendations in this case?

A. I know that there was a discussion process that we went through throughout the course of the whole analysis. And people had somewhat different ideas about certain issues, and we tried to work those through in a manner that enabled Staff to present a consistent case enabled.

Q. Okay.

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A. Sometimes that resulted in somebody's, you know, initial draft testimony getting revised. But we -- I personally believe that the final testimony -- and I have to admit, I haven't read Ms. Medine's final at this point. I did read one of her near final drafts. But, you know, I think there's a reasonable basis for the recommendations that have been made.

Q. So I'm asking about your concerns about the reasonableness of Ms. Medine's testimony. Could you identify what issues you felt or that you had concerns about with respect to her testimony?

A. That were in her drafts or within her final?

Q. That were in her drafts.

A. Yeah. I'm not sure.

Does that get into attorney-client?

MS. MITCHELL: Well, it can.

Q. (BY MR. PATTEN) I'm not asking about the discussion that you had. I'm just asking you sitting here today, your knowledge, what your concerns were about the reasonableness of her drafts.

A. It wasn't so much the reasonableness of it. It was kind of our effort to make things fit together. Like, some different ideas were floated about, you know, should this be in base rates, or should that be in the PPFAC, or how do we coordinate these various items between base rate

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treatment and PPFAC. And I think most of the issues revolved around that.

Q. What were your concerns about her drafts --

A. Well, mainly --

Q. -- on those issues?

A. -- that I was sponsoring the PPFAC recommendations and I was -- I wanted to hear her ideas, but ultimately we needed to talk through how different things should be handled and try to, you know, work that out.

Q. What were your specific concerns? For example, where she was making all of the changes in the PPFAC that wouldn't affect base rates or what?

A. No, because she was -- she was looking at fuel and purchased power costs. And, obviously, those are really important to the PPFAC. And we've worked with her before on fuel adjustment type cases, and I do respect her views a lot when it comes to, you know, fuel matters.

But then, on the other hand, she didn't have the Arizona background of the development of the APS power supply adjustment and the UNS Electric PPFAC. And so she hadn't had all of those discussions with Staff in those prior cases about what Staff wanted and hadn't read through all of the Commission, I guess feedback or, you know, the interest the Commission, and, especially when

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the APS PSA was being developed, how Staff had to seem to keep rewriting and rewriting the plan of administration in order to get it to the point where the Commission found it acceptable.

So I kind of brought some additional background on how the PPFACs had been recently addressed in Arizona, and Emily brought her detailed review of the company's fuel and purchased power procurement as well as her extensive expertise with coal procurement, and the equally extensive expertise of some of the other people in her firm with gas and purchased power.

So we tried to work collaboratively to get a PPFAC that we thought was good and workable for TEP and that reflected the best of our combined ideas.

I'm not sure it's -- you still might be able to benefit from some word tweaking here and there. We got the company's data requests -- I think they came in last Friday -- and apparently there's some, you know, perceived inconsistencies that we need to work out.

Q. Well, I'll ask you about those a little later today.

A. I'm not sure I have all of the answers to that.

Q. And it might be wordsmithing, I agree.

A. Yeah. We thought that the PPFAC was a good work product that reflected not only a good consideration of

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the similar clauses that have been adopted for other Arizona electric utilities recently, but also additional insights that Emily brought to the table.

Q. Let me just get back to your views of her draft testimony. What were the key changes that you recommended she make in her testimony?

A. Again, I kind of view the drafts as attorney-client discussion, because they were discussed with attorneys on the phone.

Q. Well, as expert witnesses, we're entitled to understand the bases of the opinions and how those changed, so --

A. And I don't know that I would say they changed. I would say they -- you know, we were trying to work collaboratively to get the final product, which was filed.

Q. But what changes did you recommend she make in her testimony?

A. I think there was some various wording changes, typos, stuff like that. She had gotten a response from the company on the coal inventory that didn't agree with the numbers I was seeing.

And I sent her all of the data responses that we got on coal inventory, and apparently the company had misinterpreted her question, or whatever, and told her the amount that they had in rate base for the coal inventory

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was essentially the end of test year amount, when I could clearly see from the data I was looking at that it was a 13-month average.

And she was recommending an adjustment to coal inventory. And after looking at her data and my data, I said the data they gave you in response to your question is just not accurate. That is not what they have in rate base, and I can prove it by filing the company's work papers and the company's responses to the data request that I asked. I can tell you exactly what the number for coal inventory is that they have in rate base, and it's not the number you're using in your adjustment. So then she was able to correct that in her testimony as it was filed.

Q. Any other conceptual issues that you asked her to -- that you recommended she change in her testimony?

A. I think that was the one change that I recommended that stands out, other than issues of consistency between our recommendations.

Q. And how was her initial drafts inconsistent with your testimony?

A. Well, I think in our initial drafts we were trying to work through how to address certain items in base rates versus the PPFAC.

Q. And how were your drafts different?

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A. I think they were different because -- again, this gets into attorney-client, I think.

MS. MITCHELL: Yes.

Q. (BY MR. PATTEN) I don't see how differing drafts is attorney-client privilege.

A. Well, we raised different items about, you know, should this item be a base rate item? Should it be a PPFAC item?

And then everybody put their ideas out and the attorneys kind of gave us feedback. And, you know, ultimately it was -- some of those issues were like, well, Ralph, you're sponsoring the PPFAC. What do you think is the most reasonable way to do it?

And if somebody had suggested a different idea, whether it was just an idea that they suggested verbally during the phone call or if they had actually written something down that was in their draft, you know, those got worked out during the process of discussion and editing. But there were various discussions about, you know, should it be base rates, should it be PPFAC, why does it make a difference?

And I think the ultimate call on virtually all of those, of course, was with the consensus of the Staff team. But, I mean, ultimately I'm the one sponsoring the PPFAC, and ultimately the stuff that we've recommended in

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the PPFAC are things that I ultimately concluded were reasonable.

Q. I'm still not sure the answer to the question on --

A. Yeah, I'm a bit hesitant to get into specifics, because I do believe that it -- you know, I mean, this was worked out through discussions with the Staff attorneys. And, I mean, I don't mind talking about the final drafts and what is in there, but the process of getting to the final draft and sorting through a potential array of recommendations that were not used, to me, is kind of stepping over the line into attorney-client.

Q. Was it your goal to keep base rates as low as possible?

A. Not necessarily. I mean, we tried to not manufacture a base rate increase for stuff that could just as easily and perhaps more appropriately be addressed in a PPFAC.

I guess the example there would be 2009, you know, projections of fuel and purchased power cost increases. I mean, it seems to us like that should be addressed in a PPFAC. You shouldn't artificially manufacture a base rate increase for those types of costs when you can just as easily and more properly have those addressed in a PPFAC that includes a forward-looking

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component, which is what we've recommended.

Q. Okay. With respect to Mr. Antonuk's testimony, did you have any concerns about his testimony that you expressed to him?

A. I don't think so. I mean, I read his drafts. I thought they were really good.

Q. Did you have communications with Mr. Parcell?

A. Yes.

Q. Did you have any concerns about his testimony or the earlier drafts that ended up getting modified?

A. Again, I know his drafts did get modified. One of the things we had to interact with him on was the fair value rate of return, because Staff's recommendations concerning that are dependent upon the original cost rate base and the fair value rate base, which were two items for which I was responsible for the calculation.

Q. Okay. Do you recall what your discussions with Mr. Parcell were with respect to those issues?

A. Yes. Here is the numbers I have today. The next week the numbers are slightly different. And as we worked through the issues, hopefully we got it coordinated by the time he filed his final testimony.

Q. So any conceptual issues you had with Mr. Parcell's testimony?

A. I don't believe so. I think we had worked pretty

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closely together on the fair value rate of return issue, not only in this case but in some of the other recent cases.

Q. Okay. I have marked as Exhibit 1 to this deposition your prefiled testimony, which is -- I think that's the whole thing.

Could you turn to Page 32 of that? At Line 1 you testify that the cumulative effect of adopting FAS 143 is an increase of 67.5 million in net income for the year 2003.

A. Yes.

Q. And did the company actually collect an extra 67.5 million in cash?

A. Well, over the prior years in which they had collected the accumulated depreciation, I think they collected -- it was approximately 112.8 million from ratepayers in accumulated depreciation, and the 67.5 million is net of an income tax effect.

Q. Okay. So it's a non-cash item, effectively?

A. Well, depreciation is considered a non-cash expense, but when you collect it in rates you're collecting cash from ratepayers and you're recording a non-cash expense on the books.

Q. Okay. Was TEP's accounting appropriate under GAAP?

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A. Well, PricewaterhouseCoopers signed off on it.

Q. And they wouldn't sign off on it if it wasn't appropriate under GAAP?

A. Well, they, I think, anguished over it. We requested to get their work papers on it, and we've had, as you probably know, trouble in getting the work papers that show their analysis of this item.

Q. Well, I know getting copies of their work papers. I understand that you were able to look at the papers.

A. Getting copies, right. Right. We were able to look at them. It does seem like they anguished over it.

And again, the accounting is based on a premise that TEP's generation assets have been deregulated. If the regulator doesn't think that the assets have been deregulated, then this type of accounting is totally inappropriate for ratemaking purposes. It's directly counter to the Commission's depreciation rules also.

Q. Let me just ask you a question about if a regulator takes an action that it later interprets differently than what it had when it took the action, how does a company react to that? I mean, here they went through the process of moving to electric competition and, effectively, changing generation to something that would be competitively procured, if available.

That was your understanding of what the Retail

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Electric Competition Rules were intended to do, wasn't it?
A. Well, they were intended to put Arizona on a similar path to what some of the leading states like California had done. And when other states that hadn't moved as quickly saw the disaster that was happening there, they pulled back and had second thoughts about it.
Q. Right. But, I mean, second thoughts were after the fact of what they did initially and --
A. No. They -- you have to follow the whole process through. In California, the utilities had sold their generation assets. In Arizona, that didn't happen. The Commission stopped it before you had that type of situation.
Q. But the rules were adopted in 1996; correct? The Retail Electric Competition Rules?
A. I presume they were adopted somewhere along that time. I don't recall the exact date.
Q. And at that point, I mean, the companies had no option but to follow the rules. Would that be your understanding?
A. Well, I think, you know, companies are supposed to follow the rules, but sometimes they don't. And I think if the rules leave room for interpretation, you know, the companies may try to interpret them to their advantage.

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Q. What sort of foresight does a company need to anticipate a retrenchment of a regulatory position in your view?
A. I don't think you need a lot of foresight. Just open your eyes and look around. Look at what all of the other states are doing. There were a lot of states that pulled back.
Q. Aren't there currently states that --
A. The states that have went -- already went to competition, they couldn't do that much to roll back. The states that were at a similar step that Arizona was, a lot of those have retrenched, and some of the ones that have gone to competition are starting to go back. They realize it's not a good model.
I mean, the benefits of lower electric prices just haven't happened. I mean, the prices are higher. It's been a disaster for ratepayers.
Q. I mean, it was anticipated back in the late '90s that retail electric competition would result in lower rates to consumers; right?
A. Right. But that was based on natural gas prices of $2 to $2.50. So once that fundamental assumption has proven to be totally not accurate, that whole underlying premise is not accurate. And the states that could stop the deregulatory process before it had gone too far, most

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of those have done that.
Q. So are you familiar with a Track B proceeding in Arizona?
A. I have heard the Track A and the Track B discussed. I know one of them had to do with not having to sell the utility's generation assets. I don't recall if that's Track A or Track B.
Q. And have you read the Track A order or the Track B order?
A. I think at some point I did.
Q. Those decisions were part of your analysis in this case, I take it?
A. Part of the discussions we had with the Staff was to kind of go through the entire historical litany of what happened in the state in the various decisions. And since that wasn't the primary focus of my analysis, I listened to it, but I guess I didn't pay as careful attention to some of that as, you know, I would have if I was going to be the witness responsible for analyzing all of that, all of those historical events, and the implications of those on the current case.
Q. Okay. But let's get back to the FAS 143. Did any customers' rates change with the adoption of FAS 143 by TEP?
A. Did they change, or will they change now because

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the company did something they shouldn't have done?
Q. Did they change?
A. They didn't change at that point, but they will change, perhaps significantly, going forward because of this unauthorized accounting that the company implemented for regulatory purposes.
Q. And your view that it's unauthorized is based upon what?
A. It's based upon the Commission's depreciation rules, and the fact that the company did not request or receive Commission authority to make this entry.
Q. Anything else?
A. That pretty much covers it. I mean, the rules say depreciation rates have to be approved by the Commission. And to make a major accounting change like this for regulatory purposes, my understanding is they should have gotten Commission authorization and should have requested it and received it, and they didn't do that.
Q. And your view is the impact of the 1999 settlement agreement and the Commission decision approving that was insufficient authorization? Have you done that analysis?
A. Again, my understanding is that the Staff -- I can't speak for the Commission, but the Staff does not

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view TEP's generation as having been deregulated.
Q. You haven't done your own analysis of whether the '99 settlement agreement and Decision 62103 approving it implicitly or explicitly allowed -- would support the change in accounting and depreciation rates?
A. No, that's not true. I did look at it in terms of this depreciation change, and in my opinion it's unauthorized. It should be reversed in this rate case.
Q. And your basis for that is the Commission rule?
A. The Commission rule, the fact that it was not approved, and the fact that it's inappropriate for regulatory purposes.
I mean, the company apparently convinced Pricewaterhouse that it was okay for financial reporting purposes. And my understanding is that they convinced them by convincing them that their generation assets had been deregulated.
Pricewaterhouse apparently didn't ask the Commission or ask the Staff, do you agree that TEP's generation assets have been deregulated? Instead, they, you know, took the company's word for it and approved the accounting. It does look like they -- I mean, that they were not totally comfortable with that, but they ultimately went along with it.
Q. Did you review Ms. Kissinger's testimony in the

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1999 settlement agreement hearing?
A. I don't recall.
Q. That was the hearing in which the settlement was being considered by the Commission. You don't recall reviewing her testimony?
A. Her testimony in the transcript?
Q. Right. Prefiled and her testimony.
A. I may have, but I just don't recall.
Q. All right. Are you aware that in her testimony she stated that once the Arizona Corporation Commission approves the settlement agreement, the company will have a specific cost recovery plan for its assets and determinable deregulation plan. This means at that point the company will need to cease accounting for its generation assets in accordance with FAS 71.
Were you aware that she submitted testimony in support of that?
A. I think somebody at the company started developing that opinion at some point. I'm not sure of the exact origins of it, but at some point somebody at the company developed an opinion that they were off FAS 71.
And how they reached that conclusion, you know, I'm not sure. I think they ultimately relied on something in the settlement. But to me, it just seems bizarre that the other big electric in the state, Arizona Public

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Service, continued to believe that they were on FAS 71.
Q. Well, that's what I'm asking here. Ms. Kissinger testified that that was the company's perceived impact of the settlement agreement in the hearing to approve the settlement agreement. This was done before. This was -- the company's position was made clear to the Commission before the Commission approved the settlement agreement.
Were you aware of that?
A. I'm not sure that the -- you know, that that position was affirmed in anything in the settlement agreement.
Q. Well, were you aware that that was the company's position of the impact of the settlement agreement even prior to the approval of the settlement agreement?
A. I'll take your word for it.
Q. And there's nothing that you're aware of where the Commission directed the company that they were not to go on -- or FAS 71 no longer applied to them, are you?
A. Well, I think that's coming to a head in this current rate case.
Q. But at the time --
A. The implications of --
Q. -- the settlement agreement was approved, the Commission didn't direct the company to keep their assets on FAS 71, even though they knew that that was the

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company's view; is that right?
A. I don't think they said that explicitly. But by changing some of the basic premises, like approving that the company could retain their generation assets, should have caused a reevaluation of that, even if the company's initial decision that it was off FAS 71 was somehow legitimate.
Q. Well, the settlement agreement was approved in 1999; right?
A. Yes.
Q. And if the company's view was that that settlement agreement required them to go off FAS 71, that would have happened in 1999; correct?
A. Most likely, yes.
Q. And if the Commission then changed the mandatory divestiture requirement in 2002, the company's already off FAS 71 at that point; right?
A. They were off for a few years apparently.
Q. Okay. And in the Track A opinion, which eliminated the mandatory divestiture requirement, are you aware of whether the Commission ordered TEP to go back on FAS 71?
A. That's not -- would typically not be something that the Commission would do. That would be for something to TEP, say, look this situation has changed drastically.

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The competition rules said that we had to divest our assets. Now the Commission has said we don't. The Commission appears to be going on a much different track than divesting utility generation assets and procuring market power in the wholesale market. TEP probably should have at that point gone back and reevaluated what was going on.

Q. And --

A. The financial accounting is basically between TEP, its auditors, and the users of the financial statements. But in terms of regulatory accounting that affects rates, that's between TEP and the Commission.

Q. I take it you didn't consider Ms. Kissinger's testimony in support of the 1999 settlement agreement in reaching your opinions in this matter?

A. Again, I don't think that's accurate because we did review all of the stuff in the Pricewaterhouse work papers where they were addressing these issues like FAS 143 and the application of FAS 71. And to the extent that Pricewaterhouse relied on any of that and cited it in their work papers, we did look at it.

Q. With respect to Ms. Kissinger's opinion in 1999 that the approval of the settlement agreement would require the company to cease accounting for its generation assets in accordance with FAS 71, do you disagree with her

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opinion in 1999?

A. I think it's questionable.

Q. Questionable?

A. Questionable, yes.

Q. Wrong, or not necessarily wrong, or --

A. I wouldn't probably have reached the same conclusion under the circumstances. But, I mean, I'm certain that she had some basis for it.

Q. What is the accounting basis for your potential disagreement with her view?

A. Because the company was allowed to recover stranded costs.

Q. Any other reason?

A. And because the other big utility in the state reached the exact opposite conclusion.

Q. Have you reviewed the settlement agreement that the other utility had with the Commission? I assume that's APS you're referring to.

A. APS, yes. I'm trying to think if I reviewed that or not. If I did review it, I don't remember.

Q. Now, I assume you're familiar with FAS 71?

A. Yes.

Q. Do you know what the requirements are that must be met for entities to follow FAS 71?

A. Yes.

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Q. Could you just describe those generally?

A. Generally, the rates have to be set by a regulatory authority. There has to be a probability that costs will be recovered.

Q. And what level of probability of recovery do you believe applies there?

A. After some of the, you know, accounting meltdowns that we've seen in recent years, usually the auditors will want to see something in a Commission order saying that it's approved as a regulatory asset. I mean, sometimes things can get deferred without that level of approval, but it seems to me that those are being questioned a lot more stringently than they used to be.

Q. And back in -- well, strike that.

Can companies that do not meet the requirements for following FAS 71 record regulatory assets and regulatory liabilities?

A. That's part of FAS 71.

Q. So I take it the answer is no?

A. I'm not sure if there might be some circumstance. I mean, like TEP apparently split its application of FAS 71 into the generation piece where they stopped applying it, and the transmission and distribution piece where they continued to apply it.

And sometimes utilities do things slightly

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differently for regulatory accounting than they do for GAAP financial reporting.

Q. Okay. I guess to the extent if the generation assets were concluded it doesn't meet requirements to follow FAS 71, could a utility company record regulatory assets or regulatory liabilities with respect to generation-related assets?

A. If they went in and got Commission approval to do that.

Q. Without Commission approval could they do it?

A. Again, without Commission approval, the only way they could do it is if they could convince their auditors that there was a legitimate expectation that the costs would be recoverable.

Q. All right. Do you know what the GAAP standard is for recording regulatory assets?

A. I guess I have always looked to FAS 71 as the primary authority on that.

Q. So effectively the same standard as you identified for FAS 71, probable recovery?

A. Right. And usually for a regulatory asset it will be the result of an order, either an accounting order or a rate order, or some type of order from the regulatory authority.

Q. Can you confirm that every deferral covered by an

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accounting order in Arizona has been allowed full recovery in subsequent proceedings?
A. No. In fact, sometimes the accounting authority will allow the company to defer something on their books for future evaluation in the context of a rate case. So it gives them the authority to not expense the cost in the period in which it was incurred and to have it considered in a future proceeding. That doesn't mean it's necessarily guaranteed to be recovered in that proceeding when it's evaluated.
Q. Okay. FERC addressed regulatory assets and regulatory liabilities in Order 552. Are you familiar with Order 552?
A. Not by the number.
Q. I think I've got a copy in here somewhere. That may help.
MS. MITCHELL: Can we take about a five-minute break? Does he need to look at this? Because I need to desperately step to the ladies room.
MR. PATTEN: Yeah. This is not like a hearing. If you need a break, you need a break.
(A recess was taken from 10:35 a.m. to 10:50 a.m.)
Q. (BY MR. PATTEN) Could the Commission order TEP to go back on FAS 71?
A. I'm not sure if they could or not. I think that

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depending on the Commission's order, TEP would need to take that and interpret it and discuss it with their independent auditors.
I guess I would -- I've got FAS 71 in front of me now. I just would like to add something to my previous answer about that.
Q. Sure.
A. Normally we know what these things say, but we don't have them totally memorized.
Q. You don't?
A. I mean, FAS 71 does come up in a lot of cases, so we keep copies of it around our office usually readily available. And if I were faced with a question, I would go right to the pronouncement and reread it and interpret the situation based on that.
But the primary two criteria are accounting for the effects of regulation, as specified in the standard itself, is that rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met.
And the first criteria is: It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost

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in allowable costs for ratemaking purposes.
And the second criteria is: Based on the available evidence, the future revenue will be provided to permit recovery of previously incurred costs rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate adjustment clause, the criteria requires that the regulators' intent clearly be to permit recovery of the previously incurred costs.
So those are the two primary criteria under FAS 71. And when circumstances change, the companies need to reevaluate whether that applies or doesn't apply.
Q. But you don't have an opinion whether the Commission could order TEP to go back on FAS 71?
A. Well, I mean, I don't think the Commission necessarily orders the company to apply a certain accounting principle for financial reporting purposes. I think if the Commission came out in an order saying, TEP, your rates are going to be set based on cost-based regulation, we're still regulating your generation assets and your future rate recovery is going to be based on the cost, then TEP would look at that decision and say, guess what? We need to start applying FAS 71.
But I'm not sure it would be -- I mean, the Commission doesn't prescribe financial accounting

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principles for the utility. They prescribe and can prescribe regulatory accounting, and the actions of the regulator have implications, then, for financial reporting. But usually the financial reporting aspects of it are something for the utility to work out between itself and its financial auditors.
Q. Okay. Let's go back to the FERC Order 552. Did you get a chance to thumb through that?
A. Actually, I didn't. Do I need to?
Q. No. I mean, just are you familiar with that order or not?
A. It's related to allowances for sulfur dioxide under the Clear Act amendments of 1990.
Q. Okay. I get the sense that you're not particularly familiar with this order?
A. I don't recall seeing this order. I mean, it's a 1993 order, revisions to the uniform system of accounts to account for allowances under the Clean Air Act amendments of 1990 and regulatory-created assets and liabilities.
Q. Do you generally know what the FERC requirements are for recording regulatory assets?
A. I would say to the extent that they're embedded in the uniform system of accounts, yes.
Q. If you could flip to page -- I think at the bottom it says 87, but it's actually Page 93 of the order.

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And the last paragraph on that page indicates that --
MR. DUKES: He's on the wrong page. The bottom says Page 87.
MS. MITCHELL: The bottom says 87?
MR. PATTEN: The bottom says 87.
MR. DUKES: It must be like Paragraph 93 or Section 93.
MS. MITCHELL: So at the bottom of the page is 87.
MR. PATTEN: Yeah. It says Page 87 at the bottom.
MS. MITCHELL: And at the top it says 93.
MR. DUKES: In the middle, it's like Section 93.
MS. MITCHELL: Okay.
Q. (BY MR. PATTEN) And the last paragraph on that page.
A. Yes.
Q. Do you want to just read the first sentence to yourself?
A. First sentence of the last paragraph?
Q. Yeah. Fair to say that either under GAAP or the FERC order, to record a regulatory asset the company must conclude and be able to demonstrate that recovery is probables?
MS. MITCHELL: Could you have him read that into the record so when I go back and look through this I'll --

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MR. PATTEN: Sure. I can mark that as an exhibit, too.
MS. MITCHELL: Oh, okay.
THE WITNESS: The Commission will also redefine regulatory assets and liabilities to use terms more similar to those used in FASB Statement 71, in order to avoid unnecessary differences between financial statements issued for regulatory purposes and general purpose financial statements.
The term "probable," as used in the definition adopted herein for regulatory assets and liabilities, refers to that which can reasonably be expected or believed on the basis of the available evidence or logic but is neither certain nor proved.
And then it's got a footnote here to Webster's New World Dictionary.
Q. (BY MR. PATTEN) Okay. So fair to say that under GAAP or one of the FERC orders, to record a regulatory asset the company must conclude and be able to demonstrate that recovery is probable?
A. I think that's a fair statement as a simplification.
Q. Okay. Is it true that an accounting -- in your opinion, is it true that an accounting order from a regulatory commission is not necessarily sufficient

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evidence by itself that recovery is probable?
A. Most likely an accounting order would be sufficient evidence. I suppose there could be circumstances that might lead someone to conclude otherwise, but it's a good first step. Certainly it's more probable if you have an accounting order than it is if you don't.
Q. What elements would need to be in an accounting order to indicate that recovery is probable?
A. I think the nature of the item would need to be specified, and the regulator would need to at least have it approved for deferral and for consideration in a future proceeding. That would probably be the minimal requirements. You could have an order on the opposite extreme that says the utility will -- shall recover this in its next rate proceeding. That would probably be on the other extreme.
Q. I'm not sure the two -- explain the two extremes you're talking about there.
A. Okay. One is where the accounting order says a utility is allowed to defer this cost for consideration in a future proceeding. So that gives the utility permission to record it as some kind of deferred asset rather than expensing it in the period incurred. It's not 100 percent guaranteed, though, that the cost is going to be recovered

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in the future. It has to be evaluated, then, in a future proceeding. So that would be one extreme where the regulator allows the utility to defer it, but doesn't necessarily bless or guarantee the recovery.
On the other extreme would be where the regulator says unequivocally this cost shall be recovered in a future rate proceeding and recorded as a regulatory asset. That doesn't leave any doubt. I mean, there's no further review involved. When the rate case comes, the cost is just put into rates and recovered.
And I suppose there could be something between those two, depending on the specific facts.
Q. How would a prudency requirement or consideration play into that?
A. I think it's pretty common in accounting-type orders to tag those with a -- you know, as long as the costs are found to be prudently incurred, which is a pretty high standard, or sometimes prudently incurred or reasonable, which is a somewhat lower standard.
Q. Okay. If a utility is under a 10-year rate freeze and incurs a cost, what procedure would need to be followed to be able to record that cost as a regulatory asset?
A. Probably applying to the Commission for an order, an accounting order. That would be one of the obvious

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steps a utility could take.
Q. Anything else?
A. And, you know, sometimes when a regulator will allow deferral of a cost, they want to assure that the utility is not overearning during the period in which the cost is being deferred. Because if deferring the cost would allow the utility to overearn, such as during a rate moratorium period, the overearnings presumably would have covered that cost for the utility. So it would, in essence, allow them to collect that twice.
So an earnings type of test is something that the regulator may want to impose in the context of an accounting order where a cost is being deferred during a period where the utility may or may not overearn.
Q. Are you aware of any instances where a utility records a cost as an expense in one period that's not a test year, and seeks recovery of that cost in a subsequent period in connection with a rate case?
A. Well, typically, in a rate case the test year is used as a starting point for measuring the rate base and the achieved net operating income. There's a fairly wide variety of adjustments that can be made to the recorded test year data for normalization, annualization, removing nonrecurring costs, adjusting expenses that may be abnormal and nonrecurring, unreasonable or imprudent.

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And sometimes in addressing issues such as normalizations, the rate analysts will need to look at data from more than one period in order to determine what a normal level is.
Q. Okay. I'm asking, I guess, about a discrete cost that incurs outside the test year, and yet the company seeks to recover it in a rate case.
A. I would say that that does happen, and you need to look at the facts surrounding the situation. Was the cost expensed in a prior period? Was the company overearning in the period in which the cost was incurred, which essentially you could infer from that that the company has probably already recovered it and doesn't need to recover it again prospectively from ratepayers.
Was the cost abnormal? You know, why was it incurred? Is there any future benefit from the cost? And various considerations similar to those are what you would typically want to think about in terms of addressing recoverability.
Q. Are you aware of instances where a commission permits recovery of that cost in a subsequent period? I assume if they meet some of the factors you're talking about.
A. If some of the factors are met. And I think one of the key factors is has the company requested and

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received an order from the commission to -- that addresses deferred recovery. That's probably one of the key factors. But if it's more like an expense normalization type situation, I think some of the other factors would also be fairly important.
Q. Are you familiar with Emerging Issues Task Force No. 93-04, which I think is entitled Accounting For Regulatory Assets? I have a copy here you can look at.
A. Yeah. That does ring a bell.
MS. MITCHELL: Michele, let's go ahead and mark these.
(Exhibit Nos. 2 and 3 were marked for identification.)
Q. (BY MR. PATTEN) If you take a minute and skim through that, I'm going to ask you about the discussion on the second page of it.
A. Okay. I've had a chance to look at it.
Q. All right. Does that EITF Abstract 93-4 indicate that a regulatory asset could be recorded whenever it meets the probability for recovery threshold?
A. It does. I think what you're referring to is under this EITF discussion, which addresses -- I mean, this EITF abstract appears to be initially directed towards other post retirement benefits under FAS 106, but it also attempts to address a broader issue.

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And with respect to the broader issue, it states that the task force reached a consensus that a cost that does not meet the asset recognition criteria in Paragraph 9 of Statement 71 at the date the cost is incurred, should be recognized as a regulatory asset when it does meet those criteria at a later date.
And the criteria of FAS 71, Paragraph 9, were those two items that I previously referenced. So what it says is that a continual review is required, and that even if something may not initially meet the asset recognition criteria in Paragraph 9 of Statement 71 at the date the cost is incurred, it could still be recognized as a regulatory asset when it does meet those criteria at a later date.
Q. Why would you think the EITF took on this issue?
A. I think the EITF and the FASB is continually trying to clarify the interpretation of accounting standards as issues arise that were not necessarily specifically foreseen or addressed when the original pronouncements were issued.
So obviously the question came up, what if an asset doesn't or a cost doesn't initially meet the FAS 71, Paragraph 9 criteria, but subsequently does? You know, what should we do about that situation? If it wasn't initially recorded as a regulatory asset, does that mean

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that that's forever precluded from being recorded as such, or may a different fact situation require a different treatment?

So they were apparently trying to clarify that particular issue.

Q. Are you aware that many regulated entities under FAS 71 recorded -- hang on a second. Strike that one.

Are you familiar with FAS 101? I've got a copy of that one here as well.

A. I think I am, but some of these I don't have memorized by the number.

Yes, I am familiar with that one. I haven't read it recently, but I have read it at some point.

You want this one marked?

MR. PATTEN: Yeah. Let's mark this one.

(Exhibit No. 4 was marked for identification.)

Q. (BY MR. PATTEN) And do you understand FAS 101 to provide guidance on the accounting to be followed once entities no longer meet the requirements of FAS 71?

A. Yeah. The general purpose of FAS 101 is to provide guidance for financial accounting for the discontinuation of the application of FASB Statement No. 71.

Q. All right. Did you review TEP's form 10-K in the year it discontinued application of FAS 71 for their

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generation segment?

A. I did review numerous prior 10-Ks. I don't recall specifically if I reviewed the 1999 one.

Q. Do you recall whether TEP --

A. I think there's typically been some discussion in the notes to the financial statements in every TEP 10-K that I reviewed, or UniSource 10-K, there's typically been a discussion about whether FAS 71 applies, and to what portion of the operations TEP was applying it as a standard disclosure in each of their audited financial statements.

Q. And that disclosure set forth reasons why FAS 71 no longer applied or no longer was being applied to its generation segment. Is that your recollection?

A. My recollection was that it set forth that it was no longer being applied to the generation portion. I think there probably were some reasons there. I don't remember what it said, other than some allusion to TEP's interpretation of the 1999 settlement as having been an event that deregulated their generation assets.

But clearly it disclosed that FAS 71 was no longer being applied to the generation portion, and then it gave some discussion related to that. I don't recall the reasons being very extensive, but --

Q. Do you believe TEP was correct in determining

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that FAS 71 no longer applied to its generation segment?

A. Initially, in 1999, I think it was probably questionable. And as subsequent events unfolded, it seems to me it was even more questionable. You know, on the other hand, you know, the company's auditors, Pricewaterhouse, you know, concurred. So, I mean, they got a clean bill of health on the financial statements, so --

Q. Why would Pricewaterhouse concur to the discontinuance of FAS 71 and the continuing application?

A. We need to get their work papers and look at that.

Q. You saw the work papers; you just don't have copies of them.

A. Right. But when we looked at their work papers, we thought we were going to get copies because we had gotten copies in the UNS Electric and UNS Gas. So we were kind of surprised that they told us in the TEP case, where perhaps the accounting issue is even more important, we're not going to give you copies of the Pricewaterhouse analysis parts of the work papers. I mean, I can show you where we got Pricewaterhouse work papers analysis copies in the other cases.

Q. We'll work that out.

A. We had a different expectation. So it's kind

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of -- we think that we need to see the Pricewaterhouse analysis and what they actually relied upon for those conclusions.

And, obviously, we took some notes, too. But since we thought we were going to get copies, our notes were not as extensive as they would have been had we known that they were going to refuse to provide copies.

It seems to me that's a fairly important issue and will probably entail somebody from our firm going back to Pricewaterhouse to re-look at those work papers and take more extensive notes if they won't provide the copies. We even discussed whether there's going to be a need to depose somebody from Pricewaterhouse on some of these issues, but we're not happy about not getting the copies.

Q. Understood. Do you know of other entities that discontinued the application of FAS 71 and the reasons cited there for that accounting?

A. Yes.

Q. Can you give me some examples?

A. I think most telephone companies have ceased applying FAS 71.

Q. Do you know whether that would include Qwest?

A. I haven't looked at Qwest specifically, but I guess I would be fairly surprised if Qwest were still

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applying FAS 71.

Q. Okay. Are there other examples?

A. I think there have been other electric companies that have gone off FAS 71 for their generation function.

I think Northeast Utilities would be one with which I'm familiar. They had to divest their generation assets, though, and now they're subject to the whims of the wholesale market, which is not a good situation at all. But I think with the divestiture of their generation assets, I'm pretty certain that they did go off FAS 71 for that portion of their business. I believe they're still on it for -- at least for distribution, and they may be on it for transmission as well.

Q. And what state do they operate in?

A. I'm most familiar with their operation in Connecticut as Connecticut Light & Power. I think they also have an affiliate that operates in Massachusetts. I'm not that familiar with their Massachusetts affiliate. And they may have some other affiliate that operates in one of the other New England states.

Q. And any other electric utilities you're familiar with just off the top of your head?

A. I think some of the electric utilities that operate in PJM may have gone off FAS 71 for their generation.

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Q. And what was the reasons for going off FAS 71 in those instances?

A. I think that the market had moved to a competitive wholesale market. Typically, the fact situations were that utilities had divested their own generation assets and the generation portion of their rates was no longer cost-based.

It was no longer being set by their state jurisdictional regulator, other than the sense that the power costs that they were incurring by purchasing power in the wholesale market, which were typically a lot higher than what it would have been had they retained their assets, would go through some kind of process where the regulator would essentially approve those.

Q. Okay. The Commission reviewed the company's financial results for 2003 in that 2004 rate review docket; is that correct?

A. I think there was -- it wasn't a rate case. It was more of a limited -- very limited review for the sole purpose, as I understand it, of ascertaining whether the company was overearning or not based on that particular year.

Q. Did you participate in that review?

A. No.

Q. Have you reviewed the testimony of James Dorf

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that was filed in the 2004 rate review docket?

A. Yes.

Q. And did the Commission Staff propose adjustments to depreciation expense in that review?

A. They reversed the impact of the FAS 143 write-off to accumulated depreciation, and I thought he had some related impact on depreciation expense.

Q. Related to FAS 143?

A. Yes. I'm not sure that they -- I mean, it looked to me like he didn't do a very extensive analysis of depreciation rates at that juncture. I think it was a very high level review, basically intended to determine if it was -- appeared likely that the company was overearning at that point in time.

Q. So other than the FAS 143, there were no other depreciation adjustments proposed?

A. You know, it's been a while since I looked at his testimony.

Q. I have it if you want to flip through it.

A. I do have it in our office here.

Q. I only have one copy of this, though. If you want to just flip through it.

(Exhibit No. 5 was marked for identification.)

A. It looks like he made the same adjustment to reverse the FAS 143 adjustment to rate base, and then from

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my recollection I thought he had a related adjustment to depreciation expense somewhere.

Yeah. His Adjustment 11 and Adjustment 3 impacted depreciation. I think Adjustment 3 was -- let me just look it up. I thought it was Springerville.

And then Adjustment 11, I think, was his estimated impact of the impact on depreciation of the FAS 143 item, but let me just refer back to his testimony.

Yeah. So it wasn't a very detailed analysis. It was essentially a very high level analysis, it appeared to me.

Q. Regarding?

A. Regarding the whole revenue requirement.

Q. Okay.

A. I think.

Q. With respect to the FAS 143 analysis, was that testimony the basis for your conclusion in this case?

A. No. I thought he reached the right conclusion, but I reached my open conclusion independently.

Q. And did you adopt his analysis? I know the language of your testimony is almost verbatim from what he said.

A. I thought he addressed it appropriately, but I did evaluate it myself and I reached the same conclusion. I thought his analysis was very well-taken on that

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particular issue.
Q. And you didn't adopt all of his positions in that 2004 rate review, did you?
A. No. I mean, I thought it was a very high level review, and we tried to do a bit more -- quite a bit more detailed analysis in the current case consistent with it being a rate case rather than just a high level overearnings check.
Q. Do nonregulated entities like Wal-Mart require approval of depreciation rate changes as long as there's evidence supporting the change?
A. For financial reporting purposes, I think their auditors would probably have to concur that their depreciation rates were reasonable. Obviously, for tax purposes they have to comply with the guidance provided in the Internal Revenue Code and the Treasury regulations.
But Wal-Mart's prices are not set by a state regulatory authority similar to a regulated public utility. I'm not aware of any rules similar to the Commission's depreciation rules -- which I did include a copy of in Attachment RCS-3 to my testimony -- that specified that depreciation rate changes must be approved by the Commission. So it's a very different fact situation with respect to Wal-Mart.
Q. Have you seen instances where utility commissions

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have objected to utilities extending the life of their assets and effectively reducing annual depreciation expense?
A. Nothing comes to mind immediately to fit that exact fact situation. I have seen instances where regulators have required utilities to charge higher depreciation rates. Sometimes that occurs in the context of small water and sewer utilities.
And I think there's always an issue of when a depreciation rate change becomes effective, ideally the depreciation rate changes should be coordinated with a utility's rate case and changes in their regulated rates to customers. That has the advantages of promoting coordination between what ratepayers are paying for and what the company is recording on its books as depreciation expense and accumulated depreciation.
And I think the Commission Rule 14-2-102, Provision (c)(4), which requires that changed depreciation rates shall not become effective until the Commission authorizes such rates, is intended to make sure that the Commission has some say as to when new depreciation rates for a regulated utility become effective.
Q. All right. In your testimony you assume the company continued to recover through its rates depreciation expense based on the previously approved

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depreciation rates; is that right?
A. No. I pointed out that the company's last Commission approved depreciation rates were set in a prior case, and the company had implemented various changes without Commission authorization.
Q. On an overall basis, those changes in -- I guess -- strike that.
On an overall basis, the company's depreciation studies have lengthened lives and reduced depreciation rates; correct?
A. With respect to, I believe it was a couple of their generation assets, the company lengthened the lives and lowered the depreciation rates that it was recording without Commission authorization; therefore, all other things being equal, they continued to collect in rates higher depreciation rates that were embedded in rates. They continued to collect those from ratepayers, but ratepayers were not being given credit for paying those higher depreciation rates because the company's accruals to accumulated depreciation were lower.
And another major thing the company did was to remove the cost of removal portion of its generation depreciation rates, which had a major impact. And that was, I believe, primarily captured in the FAS 143 write-off.

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Q. All right. Given the company's reduced depreciation rates, the annual depreciation charges are, in fact, lower than they would have been if they had continued calculating them using previous rates; right?
A. Not necessarily. I mean, we don't know that. For the items where the company -- the company's removal of the cost of removal from depreciation rates would have two effects. One, immediately it would lower depreciation rates, but going forward, because accumulated depreciation has been drastically reduced and depreciation rates are calculated on a remaining life basis, at some point the rates are going to be higher because the accumulated depreciation balance that the company is using to calculate those rates is much lower.
The plant life extension impact on depreciation rates, if coordinated properly in the context of a utility's rate case for that implementation, would probably be something that Staff would heartily endorse.
But the fact that the company implemented this without Commission authorization in a period where there was no capture of the change in those depreciation rates, and their resultant impact on accumulated depreciation, that also had the result of understating accumulated depreciation in the context of a test year in this particular rate case.

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So there are two countervailing impacts of these depreciation rate changes. One, the lengthening of a life or the removal of a major component of depreciation rates, such as cost of removal, has the impact of reducing depreciation rates. But there's also another impact in understating accumulated depreciation that has the opposite impact and causes depreciation rates prospectively to be higher.

What those two net out to, I suspect, may be a reduction, but the Commission's rules specify that net salvage means the salvage value of property retired less the cost of removal, and that salvage is to be included in the determination of depreciation rates.

So that part of what the company has done is not consistent at all with the Commission's rules. The unauthorized changes to the depreciation rates are not consistent with the Commission's rules.

So with respect to depreciation and depreciation expense, my review of the company's depreciation study revealed that the proposed rates for distribution and general plant are fine, and we're recommending that those be adopted prospectively.

With respect to the generation depreciation rates, the fact situation and the way it has built up over the years has created a real mess, and we would like to

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work with the company to get the situation straightened out and have proper depreciation rates developed prospectively.

We have asked quite a few data requests to try to get calculations in order to do that. The company's been somewhat reluctant. I think they've provided some fairly good information, not necessarily in as much detail as we would like. And we're somewhat sympathetic to the fact that that's probably going to take some time to figure out what accumulated depreciation should have been had the authorized rates continued to be have been applied through the end of the test year.

But what we would like to see ultimately is that proper depreciation rates for the company's generation function be developed in accordance with the Commission's rules, and those rates be applied prospectively.

I'm not sure that we're going to achieve that in this rate case, but we've given it our best shot based on the information we have. And, you know, if the company is willing to come forward with additional detailed calculations, we will certainly look at that. But that is our ultimate objective in terms of the generation depreciation rates. We would like to see them done properly and in accordance with the Commission rules.

The life extensions, if it weren't for the fact

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that they were implemented unilaterally by the company without Commission authorization, I personally wouldn't have a problem with it. I don't think Staff would, other than the question of trying to coordinate the rate changes within the context of a utility rate case.

So that is, I think, where we're coming from on depreciation expense as it relates to the generation function, and that's ultimately what we would like to see the outcome be of this case.

Q. Okay. If the company had continued to charge the old depreciation rates and recorded depreciation expense using the old rates, do you know if they would have recovered their costs and earned their allowed rate of return?

A. That's really hard to say without doing a detailed analysis of each year. The high level financial statement information that I have looked at, which was provided in response to one of our data requests, show that the company earned returns on equity -- again, this is financial statement, high level stuff, not necessarily regulatory operations -- showed that they were earning a fairly healthy return in most years. Not necessarily in excess of the authorized rate of return in every year, but certainly healthy returns since 1999.

But in terms of the exact impact of applying the

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correct depreciation rates, the Commission authorized rates, versus some other unauthorized rates, you know, that's just kind of a mess that we've tried to unravel as best as we can. But I can't say that, you know, the detailed analysis is really there yet in order to totally sort that out and figure what the net impact would have been.

Q. If depreciation had been calculated at the old rates, and, in fact, the company was not earning their allowed return, would you say that the company had recovered its depreciation expense?

A. I would say if the company was earning a positive return, it had net income and it had recovered its depreciation expense.

Q. If they had not recovered their depreciation expense, would it be appropriate to reduce rate base for a theoretical level of capital recovery that had not, in fact, occurred?

A. Well, I think, you know, you're doing a 180. And you know, the company has the burden of proof here. And it's been identified that they implemented depreciation changes. The depreciation changes they implemented were not authorized. The Commission's rules require that changed depreciation rates shall not become effective until the Commission authorizes such changes.

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And we have requested a bunch of data, looked at the data, made adjustments that we -- our honest, best effort to correct the situation in the context of this rate case, but we're certainly open to more detailed information such as some of the stuff we've already asked for in order to get a better, more accurate number.

I mean, we recognize that the numbers that the company has provided us with so far are estimates. They're the best estimates we have at this point. And I believe -- I mean, I briefly had a chance to glance through RUCO's testimony that was filed simultaneous with ours, and I think they have a similar concern. I think their adjustment to accumulated depreciation is in the same ballpark as what I have calculated.

I thought that they were accepting the company's depreciation rates going forward. In other words, for all of the functions, not just the distribution and general plant, but also for generation. And I don't believe I agree with that part of their recommendation. I think there's a definite problem with the generation depreciation rates. My review of those has revealed that they weren't determined in accordance with the Commission's rules for depreciation.

Q. I guess I'm just asking – you're starting to repeat yourself from the previous answer. I'm asking a

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hypothetical there.

If TEP had not recovered its depreciation expense, I mean, would it be appropriate to reduce rate base for a theoretical level of capital recovery that, in fact, hadn't incurred?

A. Well, I think that TEP should restate its depreciation reserve as if the authorized rates had applied throughout the entire period. That's the first thing that I think needs to happen.

After TEP does that, if they want to come back with some argument about how they underearned in some year and maybe, you know, there needs to be some offset against that, we'll consider those types of arguments when they're presented.

But I think the number one thing that needs to happen is the depreciation reserve needs to be restated to the end of the test year using the Commission authorized depreciation rates.

Q. Should TEP have continued to accrue AFUDC on generation construction after the 1999 settlement?

A. Again, this gets back to TEP's interpretation that its generation was deregulated. Not accruing AFUDC is apparently based on TEP's interpretation that its generation was deregulated. A deregulated enterprise doesn't accrue AFUDC on construction projects.

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Q. Okay. I guess I'm asking your opinion on this.

A. I guess my opinion is that TEP should have reevaluated the situation in terms of the changed circumstances.

Q. At which particular changed circumstance are you focused on?

A. Probably the major change was the fact that TEP didn't have to divest the generation, and what was happening in other states after the California deregulation troubles.

Q. How do other states affect what is required in Arizona?

A. Well, I think that once other states that hadn't gone down the deregulation path saw what was happening in California, most of those states tried to put a halt to that. In Arizona, that's what happened. Arizona said, wait a minute. We don't want a California situation. We need to slow down this process. We may need to do something different.

And the fact that TEP had not yet divested its generation assets, which as I understand it was one of the specifications in the electric competition act, the fact that the Commission backed away from that and said that TEP didn't have to divest the generation assets was a major change.

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Q. Well, did they rescind the Electric Competition Rules as a whole?

A. They didn't rescind them as a whole, but they started making major, drastic changes such as not divesting the generation asset.

Q. And all states didn't retrench after California; isn't that true? In fact, some states still have retail electric competition?

A. In some states the utilities had already divested their generation assets. It's hard to go backwards once the utility doesn't have generation assets anymore. It's an entirely different situation that faces a regulator.

In states where the utilities didn't divest that were considering a deregulated retail market for generation, based on our knowledge, most of those states stopped what they were doing and rethought it.

Q. And is it your view the Commission could unilaterally modify the terms of the 1999 settlement agreement?

A. I think that's asking for a legal opinion on what the Commission could or could not do, and I'm not really representing, you know, the Staff's legal viewpoint on it.

Q. Okay. And was that a factor in any of your analysis, changes subsequent to the 1999 settlement agreement?

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A. I think the Commission is charged with, you know, utility rate regulation and protecting the public interest. And after seeing the situation in California, it would have been extremely imprudent on their part to not reevaluate where things were headed and to start asking questions about is this where we really want to go.

So as far as I can tell, the Commission acted prudently by rethinking the process, by slowing it down, by not requiring the utilities such as TEP to divest their generation assets.

MR. PATTEN: Let me change directions here on you a little bit.

Actually, if I could have two to five minutes.

MS. MITCHELL: Sure. It's a good time for a break.

(A recess was taken from 11:52 a.m. to 12:05 p.m.)

MR. PATTEN: We'll just go a little bit longer and break for lunch and then come back. And my goal is to be done by 5:00 to get us all out of here. Hopefully it will be sooner.

Q. (BY MR. PATTEN) Let's see. Mr. Smith, would you agree that salvage value is the amount received for property retired less any expenses incurred in connection with a sale of any salvageable items?

A. Yeah, in general. I mean, the definition is

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right in the Commission's rules, and it says that salvage value is the amount received for assets retired less any expenses incurred in selling or preparing the assets for sale, or, if retained, the amount at which the materials recoverable is chargeable to material and supplies or other appropriate accounts.

Q. And would you agree that in connection with utility plant that ratepayers should receive the benefits of any salvage proceeds?

A. Well, for utility plant, under the Commission's rules the net salvage amount is included in the determination of depreciation rates and is charged over the useful life of the plant. So I don't know if I would call that a benefit to ratepayers, but that's how it's done.

Q. It's intended to benefit the ratepayers as opposed to the company?

A. Well, the way it works out in practical terms is usually the salvage value is negative because there's a net cost of removal, and it results in an additional charge to ratepayers. So it usually benefits the company.

Q. I guess under the Commission rule which you just read there, are the ratepayers who are affected by the change in depreciation the same ratepayers who are charged depreciation expenses over the asset's life?

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A. To the extent that the ratepayers remain ratepayers of that particular utility, obviously there's some movement in and out of the utility service territory, and there's some intergenerational, I suppose, aspects to it over time.

Q. All right. And would you agree that the cost of removal is the cost of demolishing, dismantling, tearing down, or otherwise removing retirements of utility plant?

A. In general, the cost of removal as specified in the Commission rules means the cost of demolishing, dismantling, removing, tearing down, or abandoning a physical asset, including the cost of transportation and handling incidental thereto.

Q. Would you generally agree that in connection with utility plant that ratepayers should be charged with the removal cost?

A. I think there are different ways of addressing it for ratemaking purposes. The Arizona rules specify that depreciation is an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life, and that's one way of doing it.

Another way of doing it which is employed by a relatively small number of regulatory commissions is to just treat the cost of removal and net salvage as a

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normalized operating expense.

Q. And Arizona does the former?

A. Yes.

Q. Under that approach, the ratepayers who are receiving the output or service provided by the plant assets are the same ratepayers who are being charged the cost of removal over the assets' life; is that right?

A. I'm not -- I don't think I would put it in those terms. I mean, under the Arizona rules, the net cost of removal is included in the determination of the depreciation rates, and the depreciation rates are charged over the service life of the plant.

Whether it was the same ratepayers or not, I really couldn't say. Probably to some extent it's the same ratepayers. To some other extent it's different ratepayers. The ratepayers of that utility over a period of time would essentially pay the depreciation expense of that utility.

Q. And the ratepayers are effectively receiving the output from that plant over time; correct?

A. During the service life of the plant, the ratepayers would receive the output.

Q. And so effectively the ratepayers generically that are receiving the benefit of the plant are also paying for the eventual removal costs; correct?

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A. They're paying -- under the way Arizona does it, the ratepayers are paying for the estimated future inflated removal cost related to that asset.

Now, one of the things that FAS 143 did was raised questions about is there a legal obligation to incur that cost of removal cost. And for a good portion of the cost of removal, the company doesn't have a current legal obligation to incur that cost.

Under generally accepted accounting principles, and in general terms, if a utility doesn't have a liability, then the utility doesn't incur an expense. So FAS 143 provides for a different treatment for non-legal, what is called asset retirement obligations.

Where the utility doesn't have a current legal liability to incur that estimated future cost of removal, those would not be included in the cost of the asset and not depreciated over the asset's life. The Commission's rules concerning the treatment of depreciation for regulated utility purposes continue to provide for the different treatment that we just discussed.

Q. Most utilities accomplish through accounting -- or excuse me. Strike that.

Most utilities accomplish the accounting related to retirement of assets by using a net salvage approach by netting the estimated salvage proceeds against the

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estimated removal cost; is that fair?

A. I wouldn't say that most utilities do it that way. I think utilities -- most utilities, from my experience, will try to determine a net cost of removal either by FERC account asset classifications or for major items of plant such as generating units, perhaps even by generating unit.

And if it's a net cost of removal, that net cost of removal is added to the cost of the plant, and the accumulated depreciation is subtracted. That numerator is divided by the remaining useful life under remaining life depreciation rates, and that's how the depreciation rates are determined.

So some assets may have a net cost of removal, other assets -- and a typical example would be transportation equipment, which usually has some trade-in value, they may have a positive net salvage value.

In the instance of assets that have a positive net salvage value, my experience has been that the positive net salvage amount is subtracted from the cost of the asset in the numerator such that the depreciation rates for that particular FERC account, plant FERC account or asset category, would thereby reflect the anticipated positive net salvage in that manner.

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Q. Now, is it your understanding that --

A. I guess if what you're asking me, are the total net salvage and the total net cost of removal typically lumped together and netted out?

Q. Yeah.

A. And my experience is that, no, they're not. For a particular asset category, usually the net salvage and cost of removal would be netted out for that particular asset category, and then it would either be a net cost of removal or a net positive salvage value, but it would be restricted to that asset category.

In other words, you wouldn't take all of the utility's assets, all of the net cost of removal, and all of the positive net salvage, and net those out to one final number. I mean, I suppose it could be done, but generally my experience -- and it's probably more accurate to do it that way -- is to do it by individual asset category.

Q. Is it your understanding that FAS 143 prohibits the accrual of a negative net salvage factor as part of the depreciation rate?

A. No, I wouldn't put it in those terms.

Q. How would you put it?

A. What FAS 143 specifies is that if the utility has an asset retirement obligation for generally accepted

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accounting principles, the asset retirement obligation is added to the cost of the asset, and that cost of the asset is then depreciated over the useful life of the asset.

Q. Do you believe the only companies that can continue accruing a negative net salvage factor as part of the depreciation rate is a utility company that is under FAS 71?

A. I believe that utilities that are under FAS 71 can continue to accrue, as part of their depreciation rates, net cost of removal.

If there is a legal obligation to retire an asset, that would come under FAS 143, and the analysis would be is there a current legal obligation. And if there is one, then it becomes part of the cost of the asset for generally accepted accounting principles.

Q. If the utility is treating an asset outside of FAS 71, can it accrue a negative net salvage factor for that asset?

A. Well, that's one of the questions we're facing here. According to the Commission's depreciation rules, the Commission's depreciation rules say that that's how depreciation rates should be determined. It should include cost of removal, and the recovery of the original cost of the asset less its net salvage occurs over the service life.

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So for financial reporting purposes, you know, you may get a different answer; apparently the company did. For regulatory accounting purposes and for ratemaking purposes, the Commission's depreciation rules specify what needs to be done.

Q. So your delineation there is GAAP versus regulatory accounting?

A. There could be a different treatment for GAAP and regulatory accounting. That's not unusual for that to occur.

Q. So Wal-Mart would not include an accrual for non-legal retirement obligations in its depreciation rates; right?

A. I wouldn't think so. I have not really studied Wal-Mart's depreciation rates.

Q. Here is a hypothetical for you. Not mine, but I'm going to ask it.

If Wal-Mart constructed a generating unit to supply power to itself, that generating plant would be depreciated without considering cost of removal for non-legal retirement obligations; correct?

A. Again, based on my general understanding, without, you know, having evaluated Wal-Mart, if it's a non-legal retirement obligation, it wouldn't be recorded as part of the asset, and, therefore, it wouldn't be

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depreciated over the life of the asset.

Q. Okay. Continuing the hypothetical, if at some point Wal-Mart sold this generating unit to a rate regulated utility at its net book value, there would be no cost of removal embedded in the accumulated depreciation, would there?

A. I would think not.

Q. So there would be no cost of removal embedded; right?

A. Most likely not.

Q. Okay. Would the acquiring utility record a cost of removal of regulatory liability upon closing of the purchase?

A. I'm not sure.

Q. What would you need to know to decide one way or the other?

A. I probably would want to see some kind of closing statement of all of the asset values and have some time to think about it.

Q. Okay. Would the acquiring utility be required to record a cost of removal regulatory liability upon closing the purchase?

A. I'm not totally sure without researching it. It would probably take the form of an acquisition adjustment under the regulatory accounting.

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Q. All right. I think you indicated earlier that ratepayers effectively should pay the cost of removal on utility assets; correct?

A. Well, the Arizona depreciation rules appear to require that the cost of removal be included in the determination of depreciation rates, which are ultimately paid for by ratepayers as part of the cost of service.

Q. And then following up on this hypothetical, would the utility that acquired the generating unit from Wal-Mart be able to accrue the cost of removal for the unit over its remaining life?

A. A utility in Arizona?

Q. Yes.

A. Is it following the Commission's depreciation rules?

Q. I would assume so.

A. Then probably, yes.

Q. Would amounts collected from ratepayers be shown as accumulated depreciation or as a regulatory liability?

A. For the accumulated depreciation that represents the recovery of the original cost of the plant over its useful life, that would typically be shown as accumulated depreciation. For amounts that were recovered through depreciation rates for net cost of removal, for regulatory accounting purposes that could be shown as accumulated

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depreciation; for financial reporting purposes that is to be reported as a regulatory liability on the utility's financial statements.

And I believe that's what TEP essentially does with respect to its distribution and generation plant assets. It reports a regulatory liability on its financial statements for the cost of removal that had been collected in depreciation rates.

MR. PATTEN: Want to break for lunch?

MS. MITCHELL: Okay.

(A recess was taken from 12:26 p.m. to 1:15 p.m.)

Q. (BY MR. PATTEN) I've got another hypothetical for you.

MR. DUKES: We can call it Kmart.

Q. (BY MR. PATTEN) Assume a utility owns a generating plant and considers non-legal retirement obligations in determining its depreciation rates and depreciation expense.

Assume that the regulator allows recovery of the depreciation expense, including the cost of removal factor, in determining revenue requirements.

Okay. If this situation occurred before the adoption of FAS 143, would the cost of removal component of annual depreciation be recorded as accumulated depreciation?

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A. Okay. Let me make sure I got the hypothetical. Utility owns a generating plant. It includes cost of removal for non-legal retirement obligations in its depreciation rates.

Q. Right.

A. And the regulator allows depreciation expense, including the cost of removal.

Q. Right. In determining revenue requirements.

A. On its regulated books, the utility would record the cost of removal in accumulated depreciation because it relates to non-legal retirement obligations for financial statement reporting purposes. It's my understanding that they would have to reclassify that for financial reporting purposes as a regulatory liability. And some regulators may order the utility to reclassify it as a regulatory liability for regulatory accounting purposes as well.

Q. And that would be even prior to FAS 143 being in place?

A. Most likely the issue would have arose after FAS 143 was in place. Was that part of the hypothetical, prior to FAS 143?

Q. I was asking before, yeah.

A. Prior to FAS-143, it would have been recorded in accumulated depreciation for both regulatory accounting purposes and for financial reporting purposes --

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Q. Okay.

A. -- under the GAAP.

Q. And after FAS 143 what would be done?

A. After FAS 143, for regulatory accounting purposes it could still remain in accumulated depreciation. Another option would be that the regulator could order the utility to record that accumulated amount as a regulatory liability.

For financial reporting purposes, after FAS 143 the accumulated cost of removal amount for non-legal retirement obligations would need to be reclassified on the financial statements as a regulatory liability.

Q. Okay. Now, you indicated that the utility commission could order them to record it as a regulatory liability. Could they record it as a regulatory liability without an order of the commission?

A. I'm not sure. I would have to think about that. I think the utility would probably want to keep it in accumulated depreciation as opposed to a regulatory liability. I think if the utility did record it as a regulatory liability without authorization from the commission, I'm trying to imagine a situation why the regulator would object to that and can't really think of one off the top of my head.

Q. Okay. Add an assumption to the hypothetical

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here. That the utility regulator required the utility to refund the cost of removal to ratepayers before the related plant was retired.

A. In other words, treat that as an incremental assumption on top of the other assumptions?

Q. Right. And with those assumptions, if subsequently the utility regulator decided that the ratepayers needed to pay for the cost of removal upon retirement of the plant, what are the ways for this to be accomplished?

A. Okay. So the cost of removal that had previously been accumulated had been entirely refunded to ratepayers as part of the hypothetical, and the ratepayers would need to pay for the cost of removal at the retirement of the plant. In other words, when the actual cost is being incurred?

Q. Uh-huh.

A. I suppose that one way to do that would be to treat the cost of removal as a normalized operating expense just as any other O&M expense. Some ways I have seen that being done for regulatory purposes would be to use, say, a five-year average of the most recent actual information and just treat it as a normalized operating expense.

Q. Could they require the ratepayers to pay the cost

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of removal through a remaining life estimate?

A. I don't understand what a remaining -- what you mean by remaining life estimate.

MR. PATTEN: All right. I'll get a clarification.

(An off-the-record discussion ensued.)

Q. (BY MR. PATTEN) Through the depreciation rates.

A. Well, I mean, the way remaining life depreciation works, as I explained earlier, basically the numerator is the original cost of the plant. Cost of removal, the estimated future cost of removal for non-legal obligations would be a subtraction. The amount of accumulated depreciation would be a subtraction, and the denominator, what all of that stuff is divided by, would be the remaining life.

So in your hypothetical, the cost of removal is zero, and the cost of removal in the accumulated depreciation portion is also zero. So I'm not really sure how that would work. I mean, if you say zero of, say, remaining life of 15 years, your cost recovery for that number is zero. If you divide anything -- zero by anything, it's zero. So you would essentially not be including any cost of removal, unless you start changing your assumptions.

Q. Under those assumptions, though, the utility regulator should have the ratepayers pay it; correct?

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A. Again, you have got like a pile full of assumptions here. And one of your assumptions is that there is no more cost of removal during -- being accrued in depreciation rates. I thought that was essentially what one of your assumptions was.

And as I said, an alternative way of addressing cost of removal is to treat the actual cost of removal as a normalized operating expense. Cost of removal is a legitimate expense of the utility. As such, it should be recovered from ratepayers.

The two general methods of doing it are, one, through depreciation rates, which according to my reading of the Commission's depreciation rules -- and I think this was even clarified further in a decision in not the last APS rate case but the one prior to that, where an issue was raised of some alternative treatments for ratemaking recognition of cost of removal.

So that's the way the Commission does it in Arizona, but there is this other alternative out there that you could treat as a normalized operating expense. I would think that if the Commission wanted to go down that route, and I believe there would be some merit, possibly, to doing it that way, they might want to have a generic proceeding and they might want to change their depreciation rules to provide for that alternative.

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Because the depreciation rules, as I understand it, do affect all of the utilities that the Commission regulates, you know, not just one particular utility in which an issue might be raised.

Q. Okay.

A. And because that would involve a change to the rules, maybe the best forum for it would be some kind of generic proceeding where the rules are reexamined. But again, I mean, I suppose it could be done on a case-by-case basis in a utilities rate case, but then it should be acknowledged that, you know, this is why it's being done, and it is an exception from the method that's specified in the depreciation rules.

Q. Okay. So what I'm hearing is despite the method for the cost -- despite the method, cost of removal is a cost to be recovered from ratepayers; correct?

A. Right. And there are two -- like I described there are two --

Q. Right.

A. -- generalized ways of dealing it, either over the life of the plant, or as a normalized operating expense would essentially recognize the cost as it's actually incurred.

Q. Okay. Off the hypothetical. Turning to our instant case, are you aware that the cost of removal

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component of accumulated depreciation was included in the determination of the transition recovery asset in the 1999 settlement agreement?

A. I think my general familiarity with stranded cost type determinations is that typically there will be a comparison between the net book value of the plant and some kind of market estimate, and that would be how the plant related estimate of stranded costs would be derived.

Now, as subsequent history has shown, the assumptions that people were making back at that time were way off. I mean, they were based on assumptions that relatively low natural gas prices would continue, that newly built natural gas fired generating units could produce electricity at a lower cost than legacy coal units. And the actual situation that has developed subsequently has essentially shown just the opposite.

Q. Right. But at that time in 1999, net book value would be -- would that be an assumption at that time or a known value at that time?

A. Well, the net book value was compared with some kind of market estimate. And the market estimate, as subsequent history has shown, turned out to be wildly wrong.

If anything, TEP has, you know, hundreds of millions, if not, you know, a billion or more dollars

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worth of stranded benefits from being able to retain its coal-fired plants. I think back when stranded costs were being determined, you know, they came up with a number that assigned some stranded cost recovery to TEP's generation.

Q. Right. And do you understand that the cost of removal component of accumulated depreciation was factored into determining the $450 million to be recovered under the 1999 settlement agreement?

A. It would have been part of the net plant amount at that time. Again, all of those assumptions have proven to be, you know, grossly wrong based on subsequent history. But somebody took a guess at that time and that's how they did stranded costs.

Q. But the net book value wasn't a gross mistake, was it?

A. But the difference between the net book value and the assumed market value, the assumed market value was a gross mistake. The net book value was presumably a per book number.

Q. And is it fair to say that gross mistake was made by the Commission as well as all of the parties?

A. I think it was made by commissions across the country. I mean, nuclear plants were -- typically generated, you know, huge sums of stranded cost, and the

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subsequent operation of those plants has proven that they've been extremely valuable assets to the companies that have purchased them.

The fuel cost is quite low compared to alternative sources of generation such as natural gas, which tends to set the market price in a lot of these areas. And, you know, if you can produce power at the variable cost of 40 or 50 mils per kilowatt and it's being priced out at, you know, 6, 7, 8 cents, you know, there's a huge profit margin there. And the utilities that picked up some of these nuclear plants for cents on the dollar have made out very well.

So there were a lot of really, you know, bad assumptions that went into the calculation of utilities' stranded costs, and it wasn't necessarily confined to one particular jurisdiction. You know, the whole industry was looking at numbers that just haven't proved to be anywhere close to reality --

Q. All right.

A. -- and the way things have subsequently developed.

Q. Given that the cost of removal component of accumulated depreciation was included in the net book value that was ultimately used to set the fixed CTC, wouldn't that mean that the CTC would have been higher if

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there was no cost of removal included in that determination?

A. If there was no CTC, I mean, if there was no cost of removal in accumulated depreciation, the net plant value would have been higher.

Q. And the CTC would have been higher as a result?

A. The difference between net plant and a market value that presumably was lower than the net plant, the difference would have been larger.

Q. Okay. And as such wouldn't the cost of removal component of accumulated depreciation have already been refunded to ratepayers through the CTC?

A. No. The CTC was collected from ratepayers. Ratepayers paid CTC to the utilities.

Q. But they paid less of the CTC than they would have paid?

A. But they still paid CTC. And if you look back with 20/20 hindsight, I mean, there was no stranded cost for a utility like TEP that had coal-fired generation. TEP had stranded benefits.

So if you look back with 20/20 hindsight, you could say that the entire collection of CTC for a utility like TEP was a mistake. Ratepayers paid too much. There was no real stranded cost, and an estimate was made at that point in time that assumed stranded costs.

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Subsequent events have shown that there was no stranded cost. There was a huge benefit to TEP from retaining its coal-fired generation.

Q. Was TEP's overall rate increased to recover the CTC?

A. No. It was frozen to recover the CTC.

Q. Could you tell us where FAS 143 requires that utilities establish regulatory liabilities for non-legal AROs recorded as accumulated depreciation?

A. Yeah. Can I get a document?

Q. Yeah.

A. I don't need that. I need the company's financial statements.

MR. PATTEN: Okay.

(A brief recess was taken.)

(Exhibit No. 6 was marked for identification.)

Q. (BY MR. PATTEN) I'm just asking with respect to FAS 143 itself and where within FAS 143 it requires that utilities establish regulatory liabilities for non-legal AROs recorded as accumulated depreciation --

A. Yeah, I believe --

Q. -- if it does provide for that.

A. I believe I discuss that in my testimony. Let me try to find you the reference. The company actually did disclose that in its 10-K, and I believe there's a quote

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in my testimony also from that.

Q. And I'm not asking about the company's 10-K. I'm asking in the text of FAS 143, or does 143 just incorporate FAS 71?

A. I'm looking for the discussion in my testimony.

Okay. I've got the 10-K now.

I start -- I have a pretty extensive discussion of FAS 143 in my testimony. I think it's referenced earlier in some of the adjustments, but a general discussion starts around Page 98 and discusses the concept of asset retirement obligations, how they're measured, how AROs are recorded for accounting purposes, and what would happen if a company does not have an asset retirement obligation pursuant to FAS 143, and also the impact of FAS 143 for electric utilities.

At Page 100, I make mention of Paragraph B73 of FAS 143, which provides an exception for regulated utilities which allow them to continue to incorporate net salvage factors or non-legal asset retirement obligations in depreciation rates even if they do not have asset retirement obligations.

I mention at Page 100, starting at Line 19, utilities are also required to determine the amount of any prior cost of removal collections relating to non-AROs that are now included in their accumulated depreciation

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accounts, and reclassify these and any such future charges as a regulatory liability on their financial statements.

And I believe the reading of FAS 143 and FERC Order 631, which is discussed on Page 101, 102, 103 of my direct testimony, has just about every accountant I know that deals with regulated utilities coming to the conclusion that if utilities have accumulated cost of removal for non-legal retirement obligations on their books in accumulated depreciation, for GAAP reporting purposes those amounts need to be reclassified on the financial statements as a regulatory -- I'm sorry -- a regulatory liability.

And on Page 103, I actually cite Page K65 out of TEP's 2006 SEC form 10-K, and I now have the actual 10-K with me if we need to look at that.

But I quote from where TEP makes its disclosure in its audited financial statements. As of December 31, 2006, TEP had accrued $80 million for the net cost of removal for the interim retirements from its transmission distribution and general plant.

And then it also mentions the amount as of December 31, 2005, which was 75 million for those removal costs. This amount is recorded as a regulatory liability.

So virtually every CPA I know that deals with regulated utilities that have these issues, and from a

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review of utility financial statement disclosures about the impacts of FAS 143, has revealed that utilities are reporting these items, and as I believe as required, on their financial statements as regulatory liabilities.

Q. Do you know if FERC requires utilities to record non-legal asset retirement obligations as regulatory liabilities?

A. I cite the FERC general decision, which was Order 631, on my testimony starting at Page 101. And my understanding is that FERC does not require that reclassification. The generic decision, FERC has integrated FAS 143 into the uniform system of accounts and utilities are required to review their long-life assets to determine if they have any AROs. Where utilities do not have AROs, charges for such amounts must be separately identified.

So my understanding is that the utility has to identify, separately identify the accumulated cost of removal amount but can do that within accumulated depreciation.

In other words, as long as they separately identify the accrued cost of removal, they don't have to reclassify it as a regulatory liability. They can leave it as a separately identified amount within accumulated depreciation.

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Q. Changing gears on you here.

Approximately what is the breakdown of your work between working for utility commissions, industry, or otherwise? If you could break that out.

A. Recently it's been heavily weighted towards utility commission staffs, but it depends on my work or the firm's work.

Q. Your work?

A. My work has been heavily weighted for work for utility commission staffs. We also work for some consumer representatives. We also work for some agencies like Federal Executive Agencies. We have a contract through the Department of Navy, and sometimes we represent them in certain jurisdictions where the Navy takes the lead on behalf of FEA.

Q. Are you currently working for any public utilities?

A. I'm not currently working for any public utilities.

Q. Is your company currently working on behalf of any public utilities?

A. That will be hard to say without looking at some time summaries.

Q. Okay. How long has it been since you have done any work for a public utility?

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A. I would have to check back through our records.

Q. Rough estimate?

A. A year.

Q. What company was that and in what context?

A. I did some work for the City of Lafayette, Louisiana. They were --

Q. They're not a public utility, are they?

A. Yeah, they are. They provide --

Q. Well, it's a municipal --

A. -- utility service.

Q. -- municipally owned though; right?

A. Yes.

Q. Not investor owned?

A. Yes.

Q. Okay. And what did you do for them?

A. They had condemned part of an Entergy distribution system that served an area within their expanded municipal boundaries, and there were some disputes about the valuation of the system and some tax issues.

Q. Okay. When was the last time you represented an investor-owned utility in a rate proceeding in front of a public utility commission?

A. I'm trying to recall. It's been a few years.

Q. Do you recall whether you were supporting a rate

Page 101

increase in that docket?
A. It's been a few years, so I don't recall exactly the specifics. We may have been supporting a rate increase. It was probably less than what another utility had proposed.
Q. Do you recall which utility it was?
A. There have been a few situations where our firm has worked for public utilities. Again, most of our work is for regulatory commission staffs or intervenors.
One of the engagements that we had for a utility involved -- I think it was called British Columbia Petroleum Corporation, which was a crown corporation in Canada operating in British Columbia. And I think there was some aspects about a pipeline transmission rate increase that they were challenging.
Q. Do you own any utility stock?
A. Not directly. I do own some broadly based mutual funds, so I'm sure through the mutual funds I own probably some utility stock. I don't own any individual stocks at all.
Q. Okay. And have you owned any utility stock in the past? Specific company utility stock?
A. I'm glad you put it in the past, because we've gotten an inheritance situation where it looks like I'm going to be ultimately getting some Detroit Edison stock,

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but that hasn't quite happened yet. But no, in the past I haven't owned any individual stocks.
MR. PATTEN: If we could have about two minutes, I'm going to switch topics completely now.
MS. MITCHELL: Okay. Sure.
(A recess was taken from 2:05 p.m. to 2:15 p.m.)
THE WITNESS: Let me just -- I don't know why I didn't think of it instantly, but we do a whole bunch of these -- I don't know about a whole bunch, but we do a fair number of these Green-e. They're like renewables, clean energy verification audits. And some of those are for what you would call regulated public utilities.
Like, we've been doing the one for Alliant Energy, Interstate Power & Light for a few years now. And we did their one last year, and I understand we're in the process of being engaged or are engaged already to do their current one.
So some of the Green-e work is for regulated public utilities. Others are for just other types of companies that are providing renewable energy, wind, solar, you know, landfill gas, that some of their energy gets sold to public utilities or to individuals, but they're not really considered public utilities, but some of them are like Alliant.
Q. You're not doing rate case work, though, for

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those companies?
A. No. This isn't rate case work. In fact, we try to be careful to -- you know, we've gotten calls from other entities about doing their Green-e work, and we try to make sure we screen them so we don't have some kind of conflict where we're doing this type of work for them and also doing work in a rate case that would -- where we would typically be working for a staff or a consumer group probably taking some positions contrary to what the utility had in its filing.
But we definitely do work and are currently working and will be working for utilities in the Green-e area.
Q. Okay. Fair enough.
A. Can I put this back now to make sure --
Q. It doesn't get lost?
A. -- it doesn't get lost.
Q. Let's turn to the Luna plant.
A. Okay.
Q. And you're proposing to put Luna in at cost and not as a market rate; is that correct?
A. Yes.
Q. And why did you reject the company's proposed rate treatment for Luna?
A. Again, this kind of goes with the overall theme

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of the case, but Staff views the company's generation as being subject to Commission regulation. And we believe that the ratemaking treatment for generation should be, unless there's some other compelling reason to deviate, should be based on cost.
Luna was a fairly recent addition, and we've reflected it at cost.
Q. What would be a reason to deviate from cost?
A. Well, a prior Commission order saying do it some other way.
Q. Anything else?
A. I guess what I had in mind was, you know, Springerville, there's an issue there about a market rate or cost, or a rate that the Commission had previously ordered be used.
Q. Okay. Any other reason why you would use something other than cost from your point of view?
A. Well, I suppose there might be. As I'm sitting here this instant, nothing comes to mind. I mean, I guess if there was some kind of abuse where the utility entered into some kind of dealings that were imprudent or unreasonable, there may need to be an adjustment to something other than cost.
Q. Okay. What if the purchase price was subsequently deemed to be above cost, even though at the

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time of purchase it may have been at cost?
A. Are you talking about the purchase price of a generating unit?
Q. Yeah.
A. And your example was the purchase price was deemed to be above cost?
Q. Yes.
A. There would typically be -- was it above cost when it occurred?
Q. Not above cost. Above market at the time the purchase was made.
A. Was above market because of some unreasonable decision-making by the utility?
Q. I don't know. I'm asking you.
A. Yeah. If it was above market at the time because of some unreasonable decision-making by the utility, I think that would call for some differing treatment possibly. You would have to know the specific facts for that particular situation.
But a utility purchased above cost for some -- based on some kind of unreasonable decision-making process would seem to me to require some kind of regulatory solution that may require something other than cost be used for the ratemaking treatment.
Q. What if the market cost of the plant had

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decreased from the time of acquisition? It was purchased at the market cost, but it had decreased since the acquisition and to the date of the test year.
How would you treat that?
A. Well, I think in general we would treat the regulatory treatment based on cost, unless there's some, you know, compelling reason to deviate.
I mean, we have calculated a fair value rate base, and we have recommended two alternative options for the rate of return on that. You know, so valuation does have some role in Arizona ratemaking in that the fair value rate base is what has to be used.
Q. Okay. Luna is not in TEP's current jurisdictional rates, is it?
A. You asked us a data request on that, and you know, I mean, it's kind of a philosophical question. It was added after the last rate case. So are any assets that were added after the rate case not in jurisdictional rates? I mean, if you want to go down that path, you could reach that same conclusion, which I don't think is -- that doesn't seem reasonable to me.
It's a recently acquired generation asset. The company has proposed a ratemaking treatment that's based on cost derived from some market information. Staff has proposed reflecting it at cost.

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When I totalled up all of the differences related to Luna, I don't believe there's a huge revenue requirement difference in the two treatments because it was so recently acquired.
Q. Did you do your own determination of what a reasonable market value would be for Luna?
A. No. We used the cost. Our recommendation is that the actual cost be used for ratemaking treatment.
Q. Right. So you don't know how TEP's $7 per megawatt proposal matches up against actual market value, do you?
A. Well, I mean, I read the company's testimony, and you know, so from that sense I read what the company said about it. But you know, it kind of gets back to the whole major philosophical difference. I mean, are we going to regulate based on cost, or are we going to use market surrogates?
The company even in its cost of service case wants to use market surrogates for some items and, you know, Staff believes that cost should be used, unless there's a compelling reason not to. And with respect to Luna, we just don't see the compelling reason.
Q. All right. So in general, if you purchase an asset at below market, how would you treat it in rate base?

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A. In general, if an asset is purchased below market, the cost that you paid for that asset would be recorded on the utility's books. If the cost of the acquirer -- I guess it depends if you bought it from another utility or it was somebody else, but potentially there could be an acquisition adjustment involved. And the regulatory treatment of an acquisition adjustment can be a controversial area.
But it would generally be the cost recorded as plant and accumulated depreciation on the utility's books, and there may be some accumulated deferred income tax amounts related to that plant. And then on the operating expense side, there would be the normal operating expenses and there would be depreciation and property taxes.
Q. And how would you treat the plant -- how would you treat that asset when the company sold it or if the company sold it?
A. If the company sold it, I think it would depend on the circumstances of the sale, whether there's a gain or loss. I mean, you would need to look at a variety of factors.
I know for some relatively minor land sales, I think the Arizona Commission has some precedent out there which would typically require that those be shared 50/50 between the utility and its ratepayers, usually normalized

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over some period of time.
For a sale of a major generating unit, if it were sold at a gain and you were back in the determining stranded cost mode, it seems like that gain would flow through to ratepayers as, you know, a stranded benefit.
But it depends on the situation. It's hard to just generalize.
Q. What if you weren't in a stranded cost mode?
A. And it was a major generating asset that was sold --
Q. Correct.
A. -- by the utility? I don't know. I have to -- I would probably want to give that more thought. I think you would have to look at how items were treated in the past of a similar nature and see if there's any precedent out there.
Q. Would it matter if it was base-load generation versus other generation owned by the utility?
A. It might. I don't know. I would really need to see the specific fact situation and probably want to do more research on the precedent.
Q. Okay. Let me just have you turn to your testimony. At the end you have a sheet of adjustments that you have made right before the schedules.
A. Is that Attachment RCS-2?

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Q. Yeah.
A. Yeah.
Q. With respect to the net operating income adjustments there identified as C-1 through C-24, are any of those adjustments made because the expense was not prudent?
A. I probably wouldn't use the term prudence to describe it. Keep in mind that a couple of the adjustments are being addressed by other witnesses, and specifically the San Juan coal contract in C-4, and there's two components relating to coal contracts in C-20, the implementation cost regulatory asset, which are being addressed by another witness, Emily Medine of Energy Ventures Analysis.
And I don't recall if she -- if her conclusions on those items were that they were imprudent, or if there were other reasons for those adjustments. I think I described at some length in my testimony the reasons for each of the Staff adjustments.
Q. And I agree with that, and I'm just trying to short circuit things here. I didn't see you identify anything as being, you know, changed as being imprudent or unreasonable. There were reasons for sharing costs or other things like that, but --
A. Yeah. I think behind the history of this

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Springerville item, I think there was a finding of unreasonableness or imprudence in the way that was originally handled by the company.
Q. That would be C-1?
A. Yeah, with Alamedo (phonetic).
Yeah. The other stuff, I think the reasons are basically described in my testimony, and --
Q. And again --
A. -- offhand, I don't recall using the word, you know, imprudent to describe any of those.
Q. Or that the level of expense was unreasonable?
A. I think that's a different matter. I think some of these may come in under the level of expense being unreasonable umbrella.
Q. But that would be explained in your testimony?
A. Yeah. Our specific reasons for doing each adjustment are explained in the testimony. You know, I suppose for some of them additional explanation could be added, but we did try to give reasons for each of the adjustments in the testimony.
Q. Okay.
A. Explain where the numbers came from and cite the references.
Q. All right. With respect to adjustment C-11, which is wholesale trading activity, margin sharing, C-12,

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gain on sale of SO2 emission allowances, and C-13 -- strike that -- C-10, short-term sales, those are items that will be in the future credited against the PPFAC rate; is that correct?
A. Yeah. The company has some data requests that we got on Friday, I think, that try to clarify some of this. And we're in the process of drafting responses to those.
Q. And I think we've had some discussion about having actually just a phone call to discuss the mechanics and operations to make sure we're on the same thing. I have just got some more general questions about PPFAC big picture issues.
A. Okay. I guess the big picture on you mentioned C-10, short-term sales, is that we have reflected an amount of gain on short-term sales in the derivation of Staff's proposed base rate revenue requirement. We've also recommended that annual fluctuations above and below that amount be treated through the PPFAC.
Q. You have done a similar thing for C-11 and C-12, the wholesale trading and the SO2 emission allowances?
A. For C-12 it's similar. For wholesale trading, we've recommended 10 percent of the net positive margin resulting from those activities be shared with ratepayers.
Q. Okay. And I guess by similar treatment I'm suggesting that the initial impact is on non-PPFAC base

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rates, and the subsequent impact will be through the PPFAC; is that right?

A. Yes. The annual changes in each of these items, short-term sales, wholesale trading activity, margin sharing, positive margin sharing of 10 percent to ratepayers and gains on sale of SO2 emission allowances, we've reflected an amount in the determination of the base rate revenue requirement, and annual fluctuations from that amount would be addressed through the operation of the PPFAC as proposed by Staff.

Q. Why didn't you just do it all through the PPFAC and use those three adjustments in setting the initial PPFAC rate?

A. I guess one of the reasons is that there's competing PPFAC start dates out there. And base rates are scheduled to become effective January 1, 2009, and we thought it was reasonable to reflect each of these items in the determination of base rates.

There are, to my knowledge, at least three different PPFAC proposals out there now. There's the company's, which would start in 2010. There's Staff's, which would start January 1, 2009. And then RUCO has proposed something different. I haven't -- I just briefly read their testimony, but it appears that they're proposing some kind of fuel adjustment that would apply to

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incremental load. I guess it's based on this ECAC mechanism that the company has proposed in the context of one of the prior cases.

But we want to make sure that these items get reflected and thought that it was important to include them in base rates for those reasons.

If it were in another context with a different fact situation, you know, it might be appropriate to either put them entirely in base rates or to put them entirely into the PPFAC. One advantage of including these items in the PPFAC --

Q. From the start?

A. No. To include them in base rates to make sure that they get reflected in rates starting January 1, 2009.

But one reason for including recognition of annual changes in these items in the PPFAC is that at least the short-term sales item can be fairly substantial and it can be volatile. And the gain on sale of SO2 emission allowances is also quite significant and that can be volatile. Emission prices, emission allowances prices can fluctuate significantly from year to year. So we think it's appropriate to recognize annual fluctuations in those items through the operation of the PPFAC.

The wholesale trading activity margin, that's not as significant. At least in terms of the test year

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amount, I think the total was something in the magnitude of 1.7 million, and our 10 percent ratepayer sharing was only like $171,000. So, you know, when you stack that up against the company's fuel costs, it's not really significant.

So, you know, that one, including that in the PPFAC, I mean, if somebody made a counter argument, no, let's not, you know, bother with that additional level of complication in the PPFAC for that item, it's not worth it due to the small dollar amount, I would probably want to think about it a little bit more, but, I mean, that's not unreasonable.

The PPFAC should be to capture large cost items that are related to fuel costs. And at least in terms of the test year amount, this wholesale trading activity net margin of only 10 percent isn't of the same dollar magnitude of some of the other items.

Q. And having the change to non-PPFAC base rates, I hear you saying there may be a four-month lag of having those reflected. Is that the main reason for doing it the way you're doing it?

A. Well, it would be more than a four-month lag. The company's PPFAC proposal --

Q. Well, I'm just saying under Staff's.

A. -- was 2010, so that would be at least a 12-month

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lag.

Q. Well, under Staff's proposal.

A. Under Staff's proposal, they're recognized January 1, 2009 starting in the rates that are effective on that date, and annual fluctuations would be recognized in the operation of the PPFAC.

Q. So under Staff's proposal is there really a mathematical difference between doing it all through the PPFAC rather than doing the initial step through base rates and then having changes that are, you know, reflecting the fluctuations through the PPFAC in subsequent years?

A. Again, you asked us that in a data request, and we're in the process of drafting the answer to that.

Q. Fair enough.

Have you analyzed the impacts on rate design of your -- of the Staff proposal specifically on large volume customers?

A. Not in detail. I have prepared, or had prepared under my supervision, a worksheet of the expenses and other items that have been identified to be addressed in the PPFAC, and we have forwarded that to Staff's rate design consultant.

Q. Who is that?

A. That's Frank Radigan.

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Q. Okay. So you don't know what necessarily the impact will be of Staff's proposal on rate design at this point?
A. We don't know. I haven't seen the Staff rate design. I have had some discussions about it, but that testimony isn't filed yet.
Q. Okay. With respect to the PPFAC, we had some concerns that, depending how you read the language, there may be sort of double crediting both initially and then subsequently where revenues would be used to reduce base rates initially, but then have an impact on the PPFAC rate later, the same revenues.
It wasn't Staff's intent to have it operate to have a double counting, was it?
A. No. No. Staff's intent was not to have any double counting.
Q. Okay.
A. But I can --
Q. You would be amenable to reworking the language to clarify that to avoid that particular --
A. Some language clarification appears to be necessary. When I drafted the PPFAC plan of administration I thought it was clear, but then I had in my mind how I thought it was supposed to work. So apparently that language wasn't as clear to some other

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people who read it.
Q. Do you know if the APS short-term sales, wholesale trading activity margin, and SO2 emission allowances were factored into their non-PPFAC base rates?
A. Again, you asked us a data request about that. We've done some preliminary research, but that research hasn't been completed.
Q. You didn't do it before preparing the proposed PPFAC here?
A. Yes, we did. I just have to go find that and check some stuff before we can complete our answer.
Q. I'm going to actually just flip through your testimony now and ask you some questions on a few things throughout here, so if you have got that in front of you.
On Page 4 at Line 23, you indicate that if the hybrid or market methodology is adopted, ratepayers should be credited for the increase in the value of TEP's generating units. Do you see that?
A. Yes.
Q. What do you mean by that, and what is the basis of that belief?
A. Well, it would be essentially the opposite of stranded cost recovery. It would be a stranded benefit credit.
Q. Okay. Is the structure of your PPFAC dictated by

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its ultimate outcome? By that I mean if it results in too high of a change, would you modify the structure?
A. You know, one of the things that we wrestled with in this case and in the recent UNS Electric case, and I guess this also goes back to the APS case in which a different witness was addressing the Staff proposed PSA mechanism. In the APS case, if you recall, Staff had not recommended what the Commission imposed, a 90/10 sharing mechanism as well as a 4 mil per kilowatt hour annual cap.
So we're trying to have -- you know, I have discussed at some length in my testimony on the PPFAC why we're not recommending either of those features in the PPFAC at this time. But then, on the other hand, TEP does have some similarities to APS. More similarities exist between TEP and APS than, say, between APS and UNS Electric. And I have gone through that discussion in my testimony.
And Staff is mindful that if it became apparent that the operation of the PPFAC was going to lead to some kind of rate shock situation, that based on our reading and understanding of the related Commission deliberations and the way the final Commission-approved power supply adjustment worked for APS, that the Commission may be expecting some kind of advice from Staff in terms of what a reasonable annual cap provision might be.

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So at this point, based on our analysis to date through the filing of my direct testimony, you know, Staff is not recommending a cap as a provision to be included in the PPFAC. But depending on what kind of numbers we see, I think the company alluded to updating its forecast of 2009 fuel and purchased power costs, you know, that recommendation may be subject to modification at some later point.
Q. Turn to Page 24.
A. Okay.
Q. In the first Q and A there, you indicate that TEP should not be allowed to set up new regulatory assets that the company expensed in prior years, and in instances where TEP had neither requested nor received Commission approval for deferral.
What is the accounting literature that supports that position?
A. I think in part it's FAS 71, but in part it's the history of utility regulation.
Q. There are Commission rules that support that position?
A. I'm not sure without doing additional research if that's specified in the Commission rules. It's been my regulatory experience that, just as stated here, as a general rate making principle or as a general matter, TEP

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should not be allowed to set up new regulatory assets for costs that the company expensed in prior years and in instances where TEP had neither requested nor received Commission approval for deferral.

Q. If the Commission were to agree with TEP and all of the items that TEP claims as implementation cost regulatory assets in the proceeding, how should TEP account for those amounts on their books?

A. That's a big if, first of all.

Q. Well, it's an if. I did say if.

A. If you want me to totally suspend my skepticism about those company proposals, and if we also assume that the Commission would approve those, the company may need to establish a regulatory asset at that point for the items, or they could just keep track of them as an off-book regulatory item that's for ratemaking purposes only.

One issue that may arise if the company sets them up as a regulatory asset is what to do about the prior period financial statements in which they were written off. After some of the accounting fiascos that have occurred, companies these days seem very reluctant to do anything that would require them to restate prior year financial statements.

Q. Let me ask you, if TEP's generation assets had,

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in fact, been deregulated in 1999, would TEP still have to seek Commission approval for deferral as you suggest in your first Q and A there?

A. It's my understanding that if TEP wants to recover a cost prospectively from future ratepayers, and it had already expensed that cost, that TEP definitely needs to seek regulatory approval before it can be allowed to charge customers for that cost.

Yeah, I mean, what I understand TEP is proposing in this case is to recover these costs that it expensed in prior years. And so that -- to me, that is cost recovery, recovery of a prior year cost that had been expensed on the company's books.

Q. Okay. Turn to Page 26. At Lines 8 through 10 you discuss Desert STAR and WestConnect costs, and you indicate that those costs have been recorded as a deferral on TEP's books and appear to have been approved by the Commission for deferral in future recovery.

What are you relying on for the statement about the approval by the Commission?

A. You know, I think we tried to confirm that back to a Commission order, and I couldn't find one on those items, but I relied on Ms. Kissinger's testimony for that, for the fact that -- I think she alluded to something which at least implied that TEP believed that those costs

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had been approved by the Commission for future recovery. So we accepted those costs based on the evidence we've seen up to this point.

Q. Down at Lines 19 through 23 on Page 26, you quote from Section 4.6 of the '99 settlement, which states, TEP shall defer for future recovery its costs to implement competitive retail access.

How do you interpret that sentence there?

A. Well, I think in the context of this rate case we've interpreted that in the manner most beneficial to TEP, essentially in the same manner that Ms. Kissinger interpreted it.

As I mentioned earlier, you know, one way of utility cost recovery can occur between rate cases if the utilities are overearning, for example.

But for purposes of the deferred direct access costs, we reviewed this statement, which I believe had also been cited by Ms. Kissinger in her testimony, and interpreted that in the same way that she did.

Q. That particular phrase, cost to implement competitive retail access, doesn't specifically define those costs, does it, or that would be covered by it?

A. No. Like I said, we gave the company a very beneficial interpretation on that item. Essentially, we used the same interpretation that Ms. Kissinger did.

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Q. And you sort of exercised your discretion in deciding how broad to interpret that?

A. No. We looked for -- we read the settlement agreement, and we looked for evidence that those costs had been deferred on the company's books. And we reached, at least based on what we've seen so far, the same conclusion that Ms. Kissinger reached.

Q. And I take it your view is that that phrase, "cost to implement competitive retail access," should be interpreted fairly broadly. It sounds like that's what you've done.

A. No. I think we interpreted it -- if you look at the Schedule B-3, we interpreted it in a manner that gave some legitimacy to the deferred direct access costs that the company had recorded on its books in a deferred asset account, Account 18190. So based on what we've seen up to this point, we concurred with Ms. Kissinger's interpretation concerning that item, and we allowed that item in rate base.

And I believe we may have also agreed with her on proposed amortization. That's on -- I think it's on Schedule C-20. Yes. We allowed the same amount of amortization for that item as Ms. Kissinger did, 2.788 million.

Q. And I take it with respect to your Schedule B-3

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that you didn't believe the San Juan coal contract, the Sundt coal contract termination, and financing costs related to generation fell within the cost to implement competitive retail access?

A. No. And we didn't think that those were legitimate regulatory assets, so we've removed those items.

Q. And who made that decision?

A. Ultimately, I'm the witness sponsoring this schedule. I believe that these adjustments were also discussed extensively with the Staff team. I know Ms. Medine had done some additional review on the San Juan and Sundt contract termination fees, but I'm ultimately the witness responsible for the adjustments shown on Schedule B-3.

Q. And so it's Staff's interpretation that some of these costs are covered by 4.6 and others aren't?

A. That some of these costs, based on the information that we've reviewed so far, appear to have been approved for deferral and recovery by the Commission in some prior order, and other ones didn't.

Q. And the prior order being the order approving the settlement agreement?

A. I think that was what Ms. Kissinger cited for the deferred direct access costs. I don't recall if some of

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the other costs were subject to some other accounting order issued by the Commission.

We requested a bunch of data requests to try to get further clarification on this, and, for instance, the responses to Staff Data Request LA-11.23 indicate that TEP had not recorded the San Juan stranded cost buyout as a regulatory asset.

And I believe in response to some other questions, or maybe even some parts of that same one, the financing costs have been written off in prior years and had not been recorded as a deferral. So we reviewed the information --

Q. And those were related to the generation assets; correct?

A. No. The coal contracts, related to coal contract termination fees.

Q. If you want to turn to Page 30 of your testimony.

A. Yes, I have it.

Q. At the bottom there, you indicate that the Decision 56659, I think the date is incorrect, but it states at Page 23 that the Commission finds the average daily burn rate should be used to calculate the fuel stock adjustment. Do you see that?

A. Yes.

Q. And does Staff believe that those Commission

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pronouncements in previous orders are binding on Staff in their recommendations in a rate case?

A. If Staff is aware of a Commission order on a particular subject, Staff generally tries to give very careful consideration to that. I don't know if I would say binding, but certainly if Staff is aware of it, it's something that should be considered by Staff in presenting its case.

Q. Is that sort of a presumption that Staff needs to overcome in its recommendation if you recommend otherwise?

A. I think if Staff was doing something different than a prior order and Staff was aware of the prior order, Staff may want some discussion of what was recommended in the prior order and why this was different. I think that's why we had some discussion at some length about some of the provisions in our recommended PPFAC, why they were different from what the Commission ordered in the APS power supply adjustor.

In this particular instance, using the average daily burn rate seemed to me -- and I believe to another Staff witness, Emily Medine -- to be a preferable method of calculating the coal inventory allowance.

Q. Okay. And that decision itself was directed to TEP specifically, unlike the APS situation where you have two separate companies. Is that a difference?

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A. You know, it was directed to TEP specifically. The APS power supply adjustor, I guess Staff thought that that had enough significance to warrant discussion --

Q. Right.

A. -- even though that decision was for another electric utility.

Q. Okay. I'm going to jump you back to your Schedule B-5. Are you there?

A. Yes.

Q. The ACC jurisdictional factor for accumulated depreciation set forth there is 94.53 percent; correct?

A. Yes.

Q. Why would the ACC jurisdictional factor of 73.68 percent for ADIT differ significantly from the asset?

A. Again, they were taken from the same source, from TEP's 2007 revenue requirement model. The ADIT item may have other stuff blended in with it.

We tried to use ACC jurisdictional factors for each item which were consistent with how the company used those same factors in its 2007 revenue requirement model. Some of the factors we tried to clarify with the company. Again, they were taken from the same source.

Q. Okay. Is it reasonable that the total company adjustment on Schedule B-5 is less than the ACC

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jurisdictional amount?
A. I guess I would wonder about the same thing. It's possible that there may be some subcalculation that needs to be done to derive the ADIT jurisdictional factor related specifically to the accumulated depreciation. I mean, usually they won't necessarily be identical, but the difference of 20 percent certainly raises questions.
Q. Okay. Was your total company ADIT adjustment on B-5 calculated by multiplying 12 million-plus by the combined federal, state tax rate of approximately 39.5 percent?
MR. DUKES: 112. You said 12.
Q. (BY MR. PATTEN) Oh, 112.
A. I would have to double check that. If you want, I can do that right now.
Q. If you've got a calculator, sure. We're just trying to understand how the number is derived there.
A. I'm not sure just by looking at the schedule. It seems like it probably would have benefited from a reference or a footnote. But if you give me a moment, I can go check that and let you know.
MR. PATTEN: Sure. It's probably a good time to take a short break, too.
MS. MITCHELL: Yes.
(A recess was taken from 3:15 p.m. to 3:22 p.m.)

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Q. (BY MR. PATTEN) Okay.
A. The answer to the question was on our Excel file, which I'm pretty sure we provided you guys a copy with.
On the Excel file for Schedule B-5, the 44,679,000 ADIT impact was hard input. It wasn't calculated. And I think it does come out to 39.62 percent, which I think is the approximate tax rate that's been used elsewhere in the case.
And I think we verified that number, then, back to some other information, including Schedule JJD-3, which was Jim Dorf's testimony in the rate check overearnings review. And since he removed the same amount for accumulated depreciation, we used the same amount he used for accumulated deferred income taxes as well.
So that's the source of the amount. It may have been mentioned in another data response somewhere. I'm not sure offhand. I suspect that that's probably where it came from.
Q. And that's talking about the total company amount numbers?
A. Right. The total company amount numbers, the 112,756,000 and then the 44,679,000 related ADIT amount, I think those came off a data response. And then we, I think, compared them with the numbers that Staff witness Dorf used, and they were identical. So that's what we

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went with for the total company amounts. And the ACC jurisdictional factors were from TEP's 2007 revenue requirement model.
Q. Okay.
A. I do agree there is a big discrepancy there. And you know, perhaps another way of doing it might have been to apply a combined state and federal tax rate to the ACC jurisdictional amount related to depreciation.
Q. That was my next question.
A. Yeah. That would probably be reasonable to do it that way.
Q. Okay.
A. And would probably be more accurate. Actually, if we did it that way, we may also need to cycle back and then look in more detail at how the overall 73.68 percent for ADIT was improved.
Q. Okay.
A. But for this particular adjustment, that would also be a reasonable way of doing it.
Q. It's my understanding there's a few other similar schedules that have sort of the same thing. I'm not going to walk you through it, but we wanted to get an understanding of how you did this for this schedule.
A. In general, we came up with total company adjustments and applied ACC jurisdictional multiplication

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factors from the company's 2007 revenue requirement model. Somewhere near the end there, there were a few of them that we had questions about, and we tried to obtain some clarification from those in data requests where we ask, you know, are these the right factors? Do these comport with the company model?
And if the company supplied us with factors that we can then go back and verify, we used those. Other than that, I think we used them from the company's Excel files in the rate model.
Q. Could you turn to Page 49.
A. Okay.
Q. And the question on Line 11 about the historical ratemaking treatment of Springerville Unit 1 indicated that Decision 56659 required TEP to adjust the revenue requirement effect of Springerville Unit 1 to reflect a $15 per kilowatt month fixed cost recovery rate.
Do you see that?
A. Yes.
Q. And at that time do you know whether the $15 per kW was actual cost or something else?
A. My recollection is that the $15 was a remedy for some unreasonable or imprudent transactions or management decisions that TEP had engaged in related to Springerville. It was intended to protect ratepayers from

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unreasonably high costs related to Springerville.
Q. On Page 50 you quote from Mr. Hutchens' testimony, and that's at Lines 3 through 7 of your testimony.
Do you disagree with Mr. Hutchens' statement?
A. I wouldn't say that I disagree with it. I wouldn't say that I disagree with the quoted portion of his testimony on Page 50. I do disagree with his proposed remedy, and I have suggested continued use of the $15 per kilowatt instead.
Q. I was asking about the quoted piece.
A. Yeah. I don't disagree with the quoted piece of it.
Q. Okay.
A. What to do about the situation, though, I disagree with his ultimate recommendation.
Q. All right. At Page 52 of your testimony, Line 25 and 26, I think that summarizes your recommendation on Springerville 1 to retain the fixed monthly rate of $15 per kW; is that correct?
A. That's what our adjustment was designed to do, was to adjust it using the fixed monthly rate of $15 per kilowatt hour month that was established by the Commission in prior proceedings.
Q. All right. When you say, "and used in prior TEP

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rate cases," what are you referring to there?
A. You have asked us a data request on that, and we're in the process of answering it.
Q. All right.
A. At least --
Q. You don't recall what you based this statement on in your testimony?
A. There were at least -- there was one -- obviously, Decision 56659 was one of the sources. And I have to look back through some information, which is what I will be in the process of doing when we answer that data request, to hopefully answer it more fully.
Q. I'm going to follow up with you on this. In preparing your testimony, did you look at subsequent TEP rate case orders, and in particular Order 57586, which is dated October 11, 1991?
A. 10/11/91. I can't really answer that without referring to some of our files where we accumulated orders.
Q. You don't cite to that order in your testimony anywhere as far as I can tell.
A. Yeah. I didn't cite to that order at least in this discussion. We did try to take pains to look at every prior order that was cited in the company's testimony, in Staff's testimony, and the 2004 rate review,

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in the 2005 proceeding related to amending the settlement agreement, or that was cited in other orders.
So I mean, we did look at a pretty extensive array of orders. I can't tell you off the top of my head if that one slipped through the cracks or not.
Q. Let me give you a copy of a Decision 57586. And I've got it on Page 5, and I think it's Finding of Fact 10.q., which was cited in that data request too. If you want to just read Finding of Fact 10.q. there, and you can read it into the record.
A. Okay. 10.q.
Q. Yeah. The green sticker is right there next to it.
A. Okay. In future rate cases the Commission shall determine the appropriate level of the Century demand charge based upon reasonable market prices, but in no event will the rate be lower than the rate allowed in Decision 56659, or $15 per kilowatt month.
If, in the restructuring, Springerville Unit 1 is converted to a direct lease, or other lease restructures occur, Staff will consider levelized lease payments. In no event will levelized lease payment amounts exceed currently approved lease payment levels reflected in rates.
Q. Did you consider the first sentence of that order

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in making your recommendation for 15kW for Springerville 1? If you recall.
A. I'm not sure if this factored into the decision or not. I think the ultimate result is that we used the $15 per kilowatt month. I mean, this specifies that the rate -- in no event will the rate be lower than the rate allowed.
Q. Doesn't it say it shall be a reasonable market price?
A. It does use the term reasonable market prices. I think that's subject to some interpretation. And then it also suggests that Staff consider levelized lease payments if Springerville Unit 1 is converted to a direct lease or other lease restructures occur.
Q. That hasn't happened, has it?
A. I'm not sure if -- as I understand it, TEP has bought out some of the equity owner interests in some of the leases. I would have to do further research and investigation to evaluate if that constitutes some kind of other lease restructure occurring.
Q. I take it you did not, in making your recommendation on Springerville Unit 1, determine what a current reasonable market price would be for it as contemplated by 10.q.?
A. Well, it doesn't say current market price. It

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says in future rate cases the Commission shall determine the appropriate level of the Century demand charge based upon reasonable market prices, and then it specifies that in no event will they be lower than the $15 per kilowatt hour month. It doesn't really say current there.
Q. But you didn't do -- you haven't determined what a market price for Springerville 1 is, either currently or historically?
A. Well, I mean, again, this goes back to part of the major philosophical difference between TEP and the other parties, including Staff, about, you know, what to do about TEP's generation. Even in the cost of service case, you know, TEP has these elements like Springerville and Luna where they're trying to get a market-based cost element included in their base rates.
Q. Well, I mean, the Commission orders suggest that that's, in fact, what should be done for Springerville 1.
A. Well, I think this provision is subject to interpretation. You know, I haven't done the research on this particular element. The research that I had done on the $15 when it was initially implemented indicated to me that that was done to remedy the result of unreasonable transactions that TEP had engaged in.
Q. How many years ago from now?
A. When Decision 56659 was issued. I believe it

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was, what, sometime -- this one came out after that, and this one was dated '91. I think the previous decision might have been '89. I could check that if the date is important.
Q. It is. It is '89.
A. And it was done to remedy a situation to protect ratepayers from unreasonable decisions and transactions that TEP had engaged in. So in that context, the continued use of the $15 we thought was appropriate --
Q. It's fair to say, though --
A. -- to cite them in this case.
Q. -- that Finding of Fact 10.q. could be read a different way to require a reasonable market price other than $15?
A. Well, I mean, what it does specify is that the demand charge, the level of the Century demand charge be based upon reasonable market prices, but in no event will the rate be lower than the rate allowed in Decision 56659 or $15 per kilowatt month.
Q. Do you recall what Staff's position was on Springerville 1 and its fixed monthly rate in the 2004 rate review?
A. Yes.
Q. And they recommended, I think, $20?
A. No. Staff recommended rejection of TEP's

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proposal, which was to use a rate of $25.67 cents.
Q. And what did Staff propose?
A. Staff noted that the Commission has historically used the rate of $15 per kilowatt month, and noted that TEP has not presented any compelling reasons to set the rate to a market level.
Then, what Staff did in the context of that earnings check review was they stripped off all of TEP's pro forma adjustments where the $25.67 rate had been applied. Staff's witness in that case, James Dorf, addressed that at Page 19 of his testimony. And I believe he mentioned that stripping off all of the TEP pro forma adjustments resulted in approximately $20 per kilowatt month. And he mentions that that would not have required any pro forma adjustment by TEP.
And he also recommended that the proper treatment of Springerville Unit 1, and whether the company should be allowed a market rate rather than a fixed rate per kilowatt month, should be evaluated in the next rate filing.
So Staff didn't agree with the company's proposed $25.67 per kilowatt hour month in the context of the 2004 rate review either.
Q. So Staff also didn't use $15 there either, did they?

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A. No. What they did was stripped off all of the pro forma adjustments to get it back to an as-recorded cost amount in the 2003 test year in that proceeding.
Q. Have you done an analysis of whether TEP's proposed $25.67 per kW month rate is a reasonable market rate for capacity for a coal plant as of now?
A. I have looked at the Springerville situation, and this deals with legacy plant. This is not a new purchase. It's an existing lease transaction.
In the context of a cost-based utility rate case, it's not common to see the utility's generation re-priced out at a current market price when its legacy generation. Typically, a cost basis would be used.
In the context of Springerville 1, because the Commission had used this $15 per kilowatt hour month as the basis for adjustments in the prior rate case or cases, and the reason the Commission did that was to remedy unreasonable decisions and transactions that TEP had engaged in, I applied the $15 rate.
If this was a new market purchase rather than an existing lease generating unit, that would be a different situation and you might apply a different rate to that situation. But Springerville is a legacy plant.
As far as I can tell, the basic provisions of the leases are still intact. They will be intact until

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various dates, which I have enumerated in my testimony at Pages 51 and 52. And the terms of the leases have various provisions which allow fair market value renewal and purchase provisions, but those leases as they have existed are continuing.

And, for example, the Springerville common leases expire in 2015, and have a fair market value renewal and purchase provisions. The Springerville common facilities leases expire in 2017 and 2021, and have a fixed price purchase provision. The Springerville coal handling facility lease expires in 2015 and has a fixed price purchase provision. So these purchase provisions haven't yet kicked in.

Q. Did Staff determine what TEP's actual cost during the test year was for the Springerville leases?

A. We made some efforts to determine that. I'm not sure we ever got it refined to the point where we can say this is the actual Springerville cost throughout TEP's case. We did make efforts. We made some efforts to do that in order to compare what the actual costs would be.

Q. It was higher than $15 per kW per month, wasn't it?

A. I would have to look. I believe so, but I would have to look back at our calculations, which were not carried to completion. I mean, we wanted to consider that

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option as well. We did consider that.

Q. Why did you drop that analysis?

A. I guess there were two reasons. First of all, we felt that we hadn't pinned down all of the amounts to get an accurate cost basis proposal assembled for Springerville.

And then two, our reading of the prior orders and the Commission's historic use of the $15 per kilowatt hour appeared to us to be a reasonable continuing remedy for a situation that had originated with unreasonable transactions on TEP's part.

Q. Over 20 years ago?

A. Right, but the plant is still there. It's the same plant.

Q. In adopting the $15 per kW amount, did you consider whether there had been leasehold improvements that TEP has made since the 1989 order?

A. I wouldn't put it in that context. We are aware of leasehold improvements, and I believe some of those have been recorded on the company's books.

In going to a cost basis type analysis, one of the things that that would involve would be putting the assets that the company removed back into rate base related to Springerville. So we were aware of that, and we made some attempts to consider that.

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I wouldn't say that it was done in conjunction with the recommendation of the $15. I would say that was done in conjunction with an investigation of a potential adjustment to put all Springerville related costs on an as-incurred cost basis.

Q. The $15 per kW doesn't include leasehold improvements or factor in leasehold improvements subsequent to 1989, does it?

A. I wouldn't think so.

Q. How should those post 1989 leasehold improvements be reflected in rates?

A. Well, I mean, what our adjustment did was basically reflected the company's removal from rate base an adjustment to operating expenses, with the only difference being that we substituted the $15 per kilowatt month that the Commission had used in the prior case or cases for the company's proposed $25.67 that the company had originally proposed in the context of the 2004 rate check, which was rejected by Staff in that case.

So that's basically all this adjustment did. It substituted the $15 for the company's $25.67 per kilowatt month.

Now, I suppose an alternative approach would be to just use actual costs in the test year, which would involve reversing a bunch of company pro forma

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adjustments. And we had made some analysis along those lines but felt like we had covered everything, and also felt that that wasn't quite as good a solution as to continued application of the $15.

Q. Despite --

A. But that would be another.

Q. Despite significant leasehold improvements subsequent to 1989, how is the company going to recover for those capital expenditures?

A. Well, if you went to a cost basis and all the company's pro forma adjustments related to Springerville were reversed, that would get us to test year cost, which would include leasehold improvements.

Q. No. I hear that. But if the Staff is going to stick to the $15 per kW, per month, how are those post 1989 leasehold improvements reflected in the rates? How do we recover on those expenditures?

A. I'm not sure you would. And that presents a problem, a legitimate concern, I believe. And one potential solution would be to go to the test year cost basis approaches, just strip off all of the company pro forma adjustments related to Springerville, and then do a further evaluation to make sure that there aren't other things that need to be considered, and use that as the ratemaking basis based on recovery of as-recorded

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costs in the test year.

I understand from briefly skimming RUCO's testimony that that's what they may have done. I haven't looked at it in detail. But we will certainly, you know, look at that type of proposal and, if that is more reasonable than continuing to use the $15 per kilowatt hour, we will make -- you know, modify our recommendations should we reach that conclusion.

Q. Another option could be to follow Finding of Fact 10.q. and adopt a reasonable market price as the Commission ordered?

A. Well, I mean, Staff has rejected that same proposal, it appears, in the context of the 2004 rate review.

Q. I'm not sure Staff ever addressed that particular Commission decision in rejecting the company's position. And I get the sense that you weren't particularly aware of that decision in making your recommendation.

A. I was aware of the Decision 56659 and the fact that --

Q. I'm talking about the --

A. -- testimony that alluded to the $15 being applied --

Q. Right. And I'm alluding to the Commission decision.

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A. -- in prior rate cases. This particular finding of fact, I could tell you now that I was not aware of that particular finding when my testimony was prepared.

Q. Okay. Page 57 of your testimony --

A. Yes.

Q. -- Line 16, you talk about association activities such as lobbying and influencing legislation that is considered non-deductible activity for federal tax income purposes, and then conclude that non-deductible activities should be disallowed for ratemaking purposes.

Are you saying that IRS deductibility of amounts is the factor that should govern ratemaking?

A. No. What I'm referring to here is that lobbying expense is tagged as a non-deductible activity by EEI itself, and they send out a letter disclosing that. And the way EEI usually terms it is they call it non-deductible activities, but what they're referring to here is basically lobbying.

And for this UARG/EEI subgroup, the letter from the EEI, dated July 26, 2006, states that 100 percent of such activities were non-deductible.

Q. If you can turn to Page 58.

A. I thought Mr. Dukes agreed with us on that one in the UNS Electric case. Lobbying should be removed.

Q. I didn't say a word. I'm just wondering what the

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standard is for removal. I would hate to have the IRS set the standard.

A. The way they refer to lobbying expense is they refer to that as non-deductible activities.

Q. Turn to Page 58. On the incentive compensation, I just want to be clear. The adjustment you're making is an attempt to share between shareholders and ratepayers and not a challenge to the overall compensation being paid to TEP employees; is that correct?

A. The way the adjustment was calculated, it resulted in a 50/50 sharing between TEP's shareholders and ratepayers of a normalized amount of performance enhancement program expense.

We are aware of some prior -- at least one prior compensation study that addressed the compensation of TEP and UniSource executives that did suggest to me that their compensation was well above average.

Q. So I'm asking more about --

A. So that's the backdrop. But for this particular adjustment, we used a 50/50 sharing, which we understand is consistent with some of the Commission's recent decisions on similar incentive compensation programs.

Q. And you're aware that for APS they allowed 100 percent of cash-based incentive compensation for non-management employees?

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A. My recollection of APS is that they disallowed stock-based compensation and allowed cash-based incentive compensation. I think there was some slightly different emphasis in Staff's analysis of the compensation in that case.

I guess we thought as guidance the recent UNS Gas decision was probably more relevant to TEP since it's basically the same incentive compensation program.

Q. So you are, in fact, making an adjustment for some of the cash-based incentive compensation?

A. Similar to what the Commission adopted in the recent UNS Gas case for the same compensation programs such as PEP.

Q. But unlike what they did at APS?

A. I mean, performance enhancement program.

In APS, there was a somewhat difference analysis and a somewhat different focus.

Q. What was the difference in the focus?

A. The difference in focus was -- as I understand it, the Staff witness James Dittmer had recommended that the stock-based compensation be disallowed and the cash-based compensation be allowed. There was some concern about the way some of the programs had been structured.

So there was some, I guess, quote-unquote, sharing there. It was just that it was determined in a

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different manner.

Q. Okay. You didn't do a similar analysis in this case?

A. We did a similar analysis for TEP that we did for UNS Gas and UNS Electric. We tried to follow those since it was the same related companies and the same compensation plans. I won't say it's exactly the same, but we tried to apply similar principles and similar evaluation.

MR. PATTEN: Can we take about a five-minute break, Robin?

MS. MITCHELL: Sure.

(A recess was taken from 4:10 p.m. to 4:20 p.m.)

MR. PATTEN: Did we mark that one decision?

THE WITNESS: No.

MR. PATTEN: Let's go ahead and mark that as the next exhibit.

(Exhibit No. 7 was marked for identification.)

MR. PATTEN: Given that we're going to have on-line discussions on the PPFAC, which was a bunch of questioning, and the fact that your daughter is ill and the fact that you're recovering, I think I'm done.

THE WITNESS: I would offer that I don't know if we need to do this on the record or not, but it might be beneficial to have some additional discussions on, you

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know, what the Springerville actual costs are.

If you think that would be helpful, I mean, we would like to be able to consider as one of our options maybe one alternative to the $15, just stripping away the pro forma adjustments and using the actual costs. And we had gone down the road quite a ways to try to do that. In the end, I didn't have -- I didn't think our numbers were, you know, firm enough or that we had considered everything.

But we would like to -- and probably the quickest way of cutting through that would be to just have some online discussions or information sharing.

MR. PATTEN: Okay. That certainly sounds like something we would be interested in talking about. And we can probably go off-line now. The depo is done.

MS. MITCHELL: Okay.

(The deposition concluded at 4:22 p.m.)

RALPH C. SMITH

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STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

BE IT KNOWN that the foregoing deposition was taken before me, MICHELE E. BALMER, Certified Reporter No. 50489 for the State of Arizona, and by virtue thereof authorized to administer an oath; that the witness before testifying was duly sworn by me; that the questions propounded by counsel and the answers of the witness thereto were taken down by me in shorthand and thereafter transcribed into typewriting under my direction; that a review of the transcript by the witness was requested; that the foregoing pages contain a full, true, and accurate transcript of all proceedings and testimony had, all to the best of my skill and ability.

I FURTHER CERTIFY that I am not related to nor employed by any of the parties hereto and have no interest in the outcome thereof.

DATED at Dearborn, Michigan, this 11th day of March, 2008.

MICHELE E. BALMER
Certified Reporter
Certificate No. 50489

CHANGES AND/OR CORRECTIONS

NAME: **Ralph C. Smith**
DATE TAKEN: **March 10, 2008**
COURT: **Arizona Corporation Commission**
NUMBER: **E-01933A-07-0402, et al.**
CASE: **TEP / Rates & Decision Amendment**

SHOULD Read

PAGE	LINE	CHANGE OR CORRECTION	REASON FOR CHANGE
18	23-24	consistent case. ~~enabled~~	Remove extra word
23	8-9	by the Filing, the company's	
		work papers, and the companies	Clarity
26	19	Here are the numbers	grammer
51	17	UNS Electric and UNS Gas cases.	word "cases" missing
72	5	assets.	plural
99	18-19	I'm currently working for a	Correct misstatement
		public utility	as explained on pp 102-103
102	20	could reach that same	
		conclusion for all subsequent	Insert missing
		asset acquisitions which I don't think	words; clarity
144	2	Felt like we had not covered	Insert missing
		everything	word; clarity

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
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Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 11, 2008

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APPENDICES

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-07-0402 AND E-01933A-05-0650

This testimony provides support for the Settlement Agreement filed on May 29, 2008, by addressing the following sections of the Settlement Agreement:

Section VIII. Renewable Energy Adjustor;
Section IX. Demand-Side Management Programs and Adjustor;
Section XVII. Rules and Regulations; and
Section XVIII. Additional Tariff Filings (including partial requirements service tariffs, interruptible tariff, demand response, and bill estimation).

This testimony also responds to Commissioner Mayes' letter of May 20, 2008, in regard to the topics of partial requirements service tariffs, demand response, and demand-side management for Tucson Electric Power.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01933A-07-0402?

A. Yes.

Q. What is the subject matter of this testimony?

A. This testimony will provide support for the Settlement Agreement filed on May 29, 2008, by addressing the following sections of the Settlement Agreement:

Section VIII. Renewable Energy Adjustor;

Section IX. Demand-Side Management Programs and Adjustor;

Section XVII. Rules and Regulations; and

Section XVIII. Additional Tariff Filings (including partial requirements service tariffs, interruptible tariff, demand response, and bill estimation).

This testimony will also respond to Commissioner Mayes' letter of May 20, 2008, in regard to the topics of partial requirements service tariffs, demand response, and demand-side management for Tucson Electric Power ("TEP"). The other topics raised in the letter will be addressed by other Staff witnesses.

SETTLEMENT AGREEMENT

Renewable Energy Adjustor

Q. What does the Settlement Agreement contain in regard to renewable energy?

A. Section VIII of the Settlement Agreement provides for the establishment of a Renewable Energy Standard and Tariff ("REST") Adjustor mechanism.

Q. What is the REST?

A. The Commission adopted the ("REST") rules on November 14, 2006, in Decision No. 69127. After certification by the Office of the Arizona Attorney General, the REST rules went into effect on August 14, 2007. The REST rules require TEP and other utilities to derive a portion of the retail energy they sell from renewable electricity technologies. Each of the utilities is required to file an annual Implementation Plan and to file a tariff within 60 days of the effective date of the rules.

Q. Did TEP file its REST tariff and Implementation Plan?

A. Yes. TEP filed its proposed REST tariff and its first annual Implementation Plan in Docket No. E-01933A-07-0594. The Commission approved a revised REST tariff and Implementation Plan in Decision No. 70314.

Q. Why does the Settlement Agreement provide for a REST Adjustor mechanism?

A. The Settlement Agreement provides for the REST tariff to become an Adjustor mechanism. Although the initial amount of this Adjustor rate would be the same as contained in the REST tariff as approved in Decision No. 70314, an Adjustor mechanism would allow an easy process for future funding changes. Subsequent changes to the REST Adjustor rates would be set in connection with the annual REST Implementation Plan submitted by TEP and approved by the Commission.

Q. What would be the initial Adjustor rate?

A. The initial REST Adjustor rate would be the same rate as on the tariff approved by the Commission in Decision No. 70314. The rate would be $0.004988 per kWh with monthly caps per service of $2.00 for residential customers, $39.00 for non-residential customers, and $500.00 for non-residential customers with demands of 3 MW or greater. The REST Adjustor rate would only change with Commission approval.

Q. Would the REST Adjustor mechanism include a Performance Incentive as TEP had proposed in its rate case application?

A. No. The REST Adjustor mechanism as included in the Settlement Agreement does not include a Performance Incentive because the costs of renewables are being paid for by ratepayers.

Q. How would the REST Adjustor rate be assessed to customers?

A. The REST Adjustor rate would be billed as a separate line item on customer bills.

<u>Demand-Side Management Programs and Adjustor</u>

Q. What does the Settlement Agreement contain in regard to demand-side management ("DSM")?

A. Section IX of the Settlement Agreement states that the Signatories support the implementation of an appropriate DSM portfolio and a related DSM Adjustor for TEP and agree to use their best efforts to implement them as soon as possible.

Q. Please explain how TEP would recover its costs for DSM.

A. A DSM Adjustor mechanism would be established for TEP. Recovery of DSM costs through a DSM adjustment mechanism would provide the flexibility to adjust the level of DSM spending as new programs are added or current programs are expanded between rate cases, while also providing timely recovery of DSM costs. Separating DSM expenses from other expenses included in base rates provides an incentive to initiate programs at any time rather than in the context of a rate case. In addition, including DSM costs in base rates could result in ratepayers paying for costs that are not actually expended by the utility.

All DSM costs, including those currently in base rates, would be put into the DSM Adjustor mechanism for recovery as a per-kWh charge, which would appear as a line item on customer bills. The portion of the $3.3 million for DSM in base rates that was diverted to fund renewables, in accordance with the Environmental Portfolio Standard rules, would revert back to DSM, and the entire DSM expenditure (plus the Low-Income Weatherization program that had not previously been considered as DSM) would be removed from base rates and flow through the DSM Adjustor mechanism.

Q. When would the DSM Adjustor mechanism begin operation?

A. The DSM Adjustor mechanism would become effective when rates from this rate case become effective. TEP can continue to propose new DSM programs for Commission approval.

Q. What costs would TEP be able to recover through the DSM Adjustor Mechanism?

A. TEP would recover all prudently incurred DSM program and related costs incurred by TEP in connection with Commission-approved DSM programs and activities. Allowable costs include costs for rebates or other incentives, including rebate processing; training and technical assistance; customer education; program planning and administration; program implementation; marketing and communications; monitoring and evaluation; and baseline studies. TEP would also be allowed to collect a Performance Incentive. There would not be an Efficiency Enhanced Financial Incentive as TEP had requested in its rate case application, because TEP should not need an extra incentive to install energy-efficient equipment that is cost-effective.

Q. **Please describe the DSM Performance Incentive.**

A. The Performance Incentive would allow customers and the utility to share the overall net benefits of the DSM portfolio. Customers would receive 90 percent and TEP would receive 10 percent of the net benefits of the DSM portfolio, excluding the Low-Income Weatherization program, the Educational and Outreach program, and the Direct Load Control program. The Performance Incentive would be capped at 10 percent of reporting period DSM spending.

Q. **How would the DSM Performance Incentive operate?**

A. The Performance Incentive would start after the first full year of implementation of the DSM Adjustor Mechanism so that DSM programs can ramp up. The net benefits would be calculated for each reporting period, and the Performance Incentive would be included in the annual true-up of the DSM Adjustor Mechanism. The net benefits would be verified through measurement and evaluation. TEP would provide Staff with workpapers and input data substantiating the numbers for net benefits and performance incentives that are included in its semi-annual DSM reports.

Q. How would the DSM Adjustor rate be calculated?

A. The total amount to be recovered through the DSM Adjustor would be calculated by projecting DSM costs for the next year, adjusted by the previous year's over- or under-collection, and adding the revenue to be recovered from the DSM Performance Incentive. The total amount to be recovered would be divided by the projected retail sales (kWh) for the next year to calculate the per-kWh rate.

Q. When would the DSM Adjustor rate be reset?

A. The DSM Adjustor rate would be reset annually on June 1 of each year, beginning June 1, 2009. TEP would file an application by April 1 of each year for Commission approval to reset the DSM Adjustor rate.

Q. Would the balance in the DSM Adjustor account accrue interest?

A. TEP would apply interest whenever an over-collected balance results in a refund to customers. Although the use of the annual true-up should provide a balance between over-recovery in some years with under-recovery in some years, projections could potentially be higher than actual DSM spending, especially during ramp-up times, resulting in an over-collected account balance. The interest rate would be based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate would be adjusted annually on the first business day of the calendar year.

Q. On what funding level would the initial DSM Adjustor rate be based?

A. The DSM Adjustor mechanism would have an initial funding level of $6,384,625. This funding level is based on 100 percent of TEP's proposed budget for existing DSM programs and 25 percent of the budget for proposed programs (as proposed in Docket No.

E-01933A-07-0401) because it will take some time for the new programs to be implemented. Therefore, $6,384,625 of the annual $12,362,500 budget would be included in the initial adjustor. The Adjustor rate would be reset on June 1, 2009. The proposed budget amounts for the initial DSM Adjustor rate are shown in the following table.

DSM Program	1st Year Budget	Percentage	Amount in Initial DSM Adjustor
Education and Outreach (existing)	$651,000	100	$651,000
Residential New Construction (existing)	$3,200,000	100	$3,200,000
Shade Tree (existing)	$160,000	100	$160,000
Low-Income Weatherization (existing)	$381,000	100	$381,000
Residential HVAC Replacement (new)	$500,000	25	$125,000
Efficient Commercial Building Design (new)	$800,000	25	$200,000
Non-residential Existing Facilities (new)	$700,000	25	$175,000
Compact Fluorescent Lamp Buydown (new)	$700,000	25	$175,000
Small Business DSM (new)	$1,300,000	25	$325,000
Direct Load Control (new)	$3,970,500	25	$992,625
		Total Amount in Initial Adjustor	*$6,384,625*

Q. What would be the initial DSM Adjustor rate?

A. Using projected kWh sales of 9,988,358 MWh, the initial DSM Adjustor Rate should be set at $0.000639 per kWh.

Q. How would the initial DSM Adjustor rate impact customer bills?

A. For a residential customer using 960 kWh per month (average usage), the initial DSM Adjustor rate would result in a monthly charge of $0.61 or $7.32 per year. A small commercial customer using 3,250 kWh in a month would pay a monthly charge of $2.08 or $24.96 per year.

Q. How can Staff and the Commission monitor TEP's DSM efforts?

A. TEP currently provides semi-annual reports on DSM in the Resource Planning dockets. In place of those DSM reports, TEP would file semi-annual DSM reports in Docket No. E-01933A-07-0401 (TEP's DSM Portfolio docket) by March 1 (for period ending December 31) and September 1 (for period ending June 30) of each year. The reports would contain, at a minimum, the following information separately for each program: a brief description of the program; predetermined program goals, objectives, and savings targets; the level of customer participation; costs incurred during the reporting period disaggregated by type of cost (such as administrative costs, rebates, and monitoring costs); a description of evaluation and monitoring activities and results; kW and kWh savings; benefits and net benefits in dollars; any program-specific performance incentive calculations; problems encountered and proposed solutions; and proposed program modifications. Findings from all research projects and other significant information would be included.

<u>**Rules and Regulations**</u>

Q. What does the Settlement Agreement contain in regard to TEP's Rules and Regulations?

A. Section XVII of the Settlement Agreement states that TEP would file revised Rules and Regulations in this docket no later than June 11, 2008. The Rules and Regulations would include the changes proposed by TEP in its rate application plus Staff's modifications to those changes. It is the intent of the Signatories that the revised Rules and Regulations not be inconsistent with the provisions of the Settlement Agreement. Signatories can raise in the hearing any contentions as to whether the proposed Rules and Regulations are inconsistent with the Settlement Agreement or are otherwise inappropriate.

Q. Please describe some of the major changes in the revised Rules and Regulations.

A. Some of the most significant changes involve the section on Line Extensions, particularly the elimination of free footage. Free footage was eliminated to be consistent with recent Commission orders for other electric utilities.

Q. What are some of the other changes to the Rules and Regulations?

A. Changes to other sections of the Rules and Regulations include:

- moving terms and conditions related to retail electric competition to a separate document, Direct Access Rules and Regulations;
- moving references to specific charges to a Statement of Additional Charges;
- adding a new section outlining the applicability of the Rules and Regulations to customers;
- removing unused definitions;
- changing the interest rate on customer deposits;
- adding language about interruption of service during a national emergency or local disaster;
- adding a late payment finance charge;
- adding an electronic billing option; and
- adding a section about the process for resolving service and bill disputes.

<u>**Additional Tariff Filings**</u>

Q. What additional tariff filings are provided for in the Settlement Agreement?

A. The Settlement Agreement provides for TEP to file, within 90 days of the effective date of Commission approval of the Settlement Agreement, the following tariffs to be developed in consultation with Staff and interested stakeholders:

a. new partial requirements tariffs;

b. an interruptible tariff;

c. a demand response program tariff; and

d. a bill estimation tariff.

Q. What is partial requirements service?

A. When a customer buys all of its electricity needs from the utility, the customer is charged for full requirements service. When a customer has self-generation facilities and buys power from the utility to supplement its electrical production and/or to supply power during scheduled and unscheduled outages, the customer is charged for partial requirements service ("PRS").

Q. Does TEP currently have PRS tariffs?

A. Yes. TEP currently has four PRS tariffs (PRS-103 through 106) from the 1980s that are only for Qualifying Facilities as defined by the Public Utility Regulatory Policies Act of 1978 and have never been updated, along with two PRS tariffs (PRS-107 and PRS-108) from 1999 for all types of self-generation. TEP has proposed eliminating those six tariffs in this case. According to TEP, there are no customers on those six tariffs. In addition, TEP has three PRS tariffs (PRS-10, PRS-13, and PRS-14) that were approved as experimental tariffs in 2003 by Decision No. 65751. The three experimental tariffs would remain in place. Currently, there are two customers on PRS-13 and one on PRS-14.

Q. If TEP currently has PRS tariffs, why should new PRS tariffs be developed?

A. Some renewable facilities, especially solar, tend to have low capacity factors. Most existing PRS tariffs were designed for customers operating large-scale cogeneration facilities with capacity factors higher than those of solar units. Because of the higher basic service and standby charges on existing PRS tariffs, customers with solar facilities often pay more for partial electricity requirements under existing PRS tariffs than they would pay for full requirements service, making operation of the solar systems uneconomical.

There is a need for new PRS tariffs for these renewable facilities that tend to have low capacity factors. These new tariffs would both protect TEP's ability to recover fixed costs and facilitate the development of renewable energy projects.

Q. What would be some of the features of the new PRS tariffs?

A. The new PRS tariffs would be designed so as to not inhibit the installation of large solar or other renewable projects. The PRS tariffs would provide for supplemental (electricity purchased from TEP that is in addition to what the customer's facility produces), standby (electricity purchased during unscheduled outages), and maintenance services (electricity purchased during scheduled outages). Supplemental service would be based on the unbundled delivery price components applicable to full requirements customers. Standby service would be priced at a level that balances TEP's cost recovery needs with the promotion of economically viable self-generation. Maintenance service would be provided at a rate that recognizes that usage may be scheduled at lower cost times.

Q. Please describe features of the interruptible tariff.

A. The interruptible tariff would provide a range of options in regard to the amount of time that TEP provides notice to customers of an impending interruption (such as 10-minute notice or 30-minute notice), the duration of interruptions (the number of hours that an interruption can last), and the frequency of interruptions (such as the number of interruptions allowed in a month or in a year). The interruptible tariff would provide credits to participating customers based on TEP's avoided capacity costs. The tariff could also provide for economic interruptions (based on TEP's cost for generating or acquiring energy at specific times) as well as interruptions based on capacity or transmission constraints.

Q. What are the potential benefits of a well-designed interruptible tariff?

A. An interruptible tariff can help a utility to avoid or defer generating capacity. The value of the interruptible load to the utility varies with the length of notice required and the allowable number of interruptions. It can also help the utility to deal with emergency situations so that the impact on other ratepayers could be reduced. If economic interruptions are allowed, it can reduce costs for all ratepayers when the utility is able to avoid very costly generation purchases. An interruptible tariff can help customers who are able to accept interruptions of their electric service to reduce their costs.

Q. What is demand response?

A. Demand response can be defined as customer intentional modifications to electric consumption patterns affecting the timing or quantity of demand and usage. Demand response programs are used to reduce customer energy usage in response to prices, market conditions, or threats to system reliability. Types of demand response programs include dynamic pricing, price-responsive demand bidding, contractually obligated curtailment, voluntary curtailment, and direct load control/cycling.

Q. Please describe the demand response program tariff mentioned in the Settlement Agreement.

A. The demand response program tariff would establish a voluntary program through which customers reduce their demand levels in response to notification by TEP of a critical peak demand situation, without any payments from TEP. This particular program would focus on interested commercial and industrial customers whose operations permit them to commit to specific load reduction targets.

TEP and stakeholders will explore a potential program where customers could receive bill credits for verifiable demand reduction over expanded hours with high incremental costs. This program would be in addition to the above program that would not offer payments.

TEP will also explore notification methods through which residential customers and smaller general service customers can contribute to critical period load reduction.

Q. Please describe the bill estimation tariff.

A. The bill estimation tariff would explain TEP's methodology for estimating bills when a meter read is not available. The tariff would address situations with varying customer and premise history. Such a tariff would be consistent with A.A.C. R14-2-210.A.5.a. The Commission has recently ordered other electric utilities to file bill estimation tariffs. The tariff would provide more transparency for customers as to TEP's procedures.

RESPONSE TO COMMISSIONER MAYES' LETTER DATED MAY 20, 2008

Q. Are you aware that on May 20, 2008, Commissioner Mayes placed a letter in the Docket requesting that the parties address in testimony or settlement the issues raised in that filing?

A. Yes. I have reviewed the above-referenced letter. As I stated earlier in this testimony, I will address the topics of PRS tariffs, demand response, and DSM. The other topics raised in the letter will be addressed by other Staff witnesses.

Partial Requirements Service Tariffs

Q. What did Commissioner Mayes request concerning PRS tariffs?

A. Commissioner Mayes stated that she would like the Parties to present the Commission with a PRS tariff that does not penalize large-scale solar projects because such a penalty would be counter to the Commission's policy of encouraging renewable energy in Arizona.

Q. Does the Settlement Agreement address PRS tariffs?

A. Yes. As discussed earlier in this testimony, Section XVIII of the Settlement Agreement provides for TEP to file for Commission approval new PRS tariffs within 90 days of the effective date of the Commission's approval of the Settlement Agreement. Those tariffs would be designed so as to not inhibit the installation of large scale solar or other renewable projects.

Demand Response

Q. What did Commissioner Mayes ask concerning demand response?

A. Commissioner Mayes mentioned that, in other states, utilities are beginning to contract with large industrial or commercial customers to voluntarily shift their usage to off-peak hours or shed load during pre-arranged time periods. Commissioner Mayes asked what demand response programs TEP would adopt as part of the Settlement Agreement.

Q. Does the Settlement Agreement address demand response programs?

A. Yes. As discussed earlier in this testimony, Section XVIII of the Settlement Agreement provides for TEP to file for Commission approval a demand response program tariff within 90 days of the effective date of the Commission's approval of the Settlement Agreement. The tariff would establish a voluntary program for commercial and industrial customers to reduce demand for specified durations upon notification by TEP of a critical situation. The Settlement Agreement also discusses the exploration of programs for other customer classes.

Demand-Side Management

Q. What questions did Commissioner Mayes ask concerning DSM?

A. Commissioner Mayes asked the following questions:

1. Should TEP be required to go beyond the levels of DSM proposed by the Parties to the original case, given that several Parties to the case had recommended no rate increase or even a rate decrease and given TEP's disproportionate reliance on coal-fired generation?
2. Do the Parties believe that a heightened commitment by TEP to DSM is a ratepayer benefit that should be offered as part of the Settlement Agreement?
3. Will any new or expanded DSM programs be implemented at the time of the adoption of any order in this case, and if not, why?
4. When will the adjustor mechanism for these programs be activated, and when will the programs be presented to the Commission for a vote?

Q. What is Staff's response to the question: *Should TEP be required to go beyond the levels of DSM proposed by the Parties to the original case, given that several Parties to the case had recommended no rate increase or even a rate decrease and given TEP's disproportionate reliance on coal-fired generation*?

A. Staff did not propose a cap on DSM spending in the original case, and the Settlement Agreement does not propose a cap on DSM spending. TEP could propose additional programs for Commission approval at any time. As discussed earlier in this testimony, the Settlement Agreement provides for the establishment of a DSM Adjustor which allows for flexibility in funding new programs. However, in regard to the issue of TEP's reliance on coal-fired generation, it is important to note that DSM provides reductions in generation from the marginal generation units or purchases which typically are natural gas-fired generation.

Q. **What is Staff's response to the question: *Do the Parties believe that a heightened commitment by TEP to DSM is a ratepayer benefit that should be offered as part of the Settlement Agreement?***

A. Staff believes that DSM is very important. Cost-effective DSM enables customers to reduce their energy bills as well as reducing the utility's costs, thereby benefiting all ratepayers. During the test year, TEP spent almost $4 million on DSM. TEP has proposed in its DSM program filing (Docket No. E-01933A-07-0401) to aggressively increase its annual DSM budget to $12,362,500. Although Staff believes that DSM is important, and supports this level of spending, the DSM programs and the associated budget are the subject of another docket and, therefore, were not at issue in this proceeding. For the reason stated above, the issue of a heightened commitment to DSM by TEP is not specifically addressed by the Settlement Agreement.

Q. **What is Staff's response to the question: *Will any new or expanded DSM programs be implemented at the time of the adoption of any order in this case, and if not, why?***

A. TEP filed its proposed DSM portfolio in Docket No. E-01933A-07-0401. The DSM portfolio consists of expanding four existing programs and introducing six new programs in 2008. The new and expanded programs can be implemented upon Commission approval of the programs in Docket No. E-01933A-07-0401.

Q. **Can TEP implement new or expanded DSM programs before the Commission issues an order in this matter?**

A. Program implementation can occur before the Commission adopts an order in this case.

Q. **What DSM programs are included in TEP's proposed DSM portfolio?**

A. The DSM programs with their annual budget amounts are shown in the following table.

DSM Program	Annual Budget
Education and Outreach (existing)	$651,000
Residential New Construction (existing)	$3,200,000
Shade Tree (existing)	$160,000
Low-Income Weatherization (existing)	$381,000
Residential HVAC Replacement (new)	$500,000
Efficient Commercial Building Design (new)	$800,000
Non-residential Existing Facilities (new)	$700,000
Compact Fluorescent Lamp Buydown (new)	$700,000
Small Business DSM (new)	$1,300,000
Direct Load Control (new)	$3,970,500
Total Portfolio	*$12,362,500*

Q. **What is Staff's response to the question: *When will the adjustor mechanism for these programs be activated, and when will the programs be presented to the Commission for a vote?***

A. The DSM adjustor mechanism would become effective when rates from this rate case become effective. However, TEP should implement the new and expanded DSM programs upon Commission approval of the programs in Docket No. E-01933A-07-0401. TEP has sufficient funding to implement the programs before the adjustor mechanism becomes effective. TEP spent almost $4 million on DSM during the test year. Since the Commission has approved TEP's Renewable Energy Standard and Tariff Surcharge (effective June 1, 2008), $2.25 million of DSM funding in base rates that had been diverted to renewables can now revert back to DSM.

The Commission approved both the Residential HVAC Replacement program and the Compact Fluorescent Lamp Buydown program at the June 2008 Open Meeting. For technical reasons, TEP is not ready to implement the Direct Load Control program at this time and has asked Staff not to process it before the end of 2008. TEP will either file major revisions to the Direct Load Control program at that time or will withdraw the program soon and refile it later in the year. Staff anticipates presenting the other seven programs to the Commission at its July 2008 Open Meetings.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-May 2005), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Arizona Public Service Company Rate Case (Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827), Arizona Corporation Commission, 2006; testimony on funding for renewable resources, net metering, green pricing tariffs, and a Power Supply Adjustor surcharge.

Tucson Electric Power Company Filing to Amend Decision No. 62103 (Docket No. E-01933A-05-0650), Arizona Corporation Commission, 2007, testimony on demand-side management, time-of-use, direct load control, and renewable energy.

Consideration, Pursuant to A.R.S. § 40-252 to Modify Decision No. 67744 Relating to the Self-Build Option (Docket No. E-01345A-07-0420), Arizona Corporation Commission, 2008, testimony on the self-build option for Arizona Public Service Company.

Sempra Energy Solutions Application for Certificate of Convenience and Necessity (Docket No. E-03964A-06-0168), Arizona Corporation Commission, 2008, testimony on the overall fitness of Sempra Energy Solutions to provide competitive retail electric service in Arizona.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985

"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees.* Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

"Staff Report on Interconnection for the Generic Investigation of Distributed Generation," Arizona Corporation Commission, 2007.

Radigan

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E- 01933A-07-0402
IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DIRECT TESTIMONY

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

JUNE 11, 2008

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DOCKET NOS. E-01933A-07-0402 AND E-01933A-05-0650

Revenue Allocation - The Settlement Agreement at paragraph 2.3 provides for base rate revenue of $828.2 million, which is a $47.1 million increase over TEP's existing base rate revenue of $781.1 million. Settlement Exhibit 3 presents a Proof of Revenue which shows how the $828.2 million (inclusive of the $47.1 million base rate increase) has been spread across the service classifications so that each class receives the same increase except that residential customers who qualify for lifeline programs do not receive a rate increase. The allocation shown on Settlement Exhibit 3 and described in subsection XVI-A of the Settlement Agreement is a reasonable resolution of the various proposals put forth by parties in their testimony.

Inclining Block Rate Structure - The Settlement Agreement, in subsection XVI-B, calls for the introduction of an inclining block rate structure. This is an important measure to encourage energy conservation. As the customer usage increases, the price for each kWh of electricity becomes more expensive. This should give customers the signal to give more consideration in using power. The rates are also seasonally differentiated between summer and winter, with the winter rates lower than the summer. The seasonal differentiation is an additional means to make customers more aware that power costs are higher during the high-usage summer periods. The largest users, though small in number, use a considerable amount of energy. Therefore, tier points were chosen for the blocks that would protect small users from seeing large increases in their bills but, at the same time, give the largest users a signal to conserve.

Time of Use Rates - The Settlement Agreement, in subsection XVI-C, provides for Time-of-Use Rates. Sending price signals to customers regarding TEP's cost to serve at different times of the year and at different times of the day provides an important energy conservation incentive. Thus, the Settlement expands the availability of time-of-use rate schedules and offers them on an optional basis rather than a mandatory basis. Further, the number of time-of-use rate schedules has been expanded in order to give customers maximum flexibility in choosing the rate schedule that best suits their lifestyle. Finally, the rate design for each of the new rate schedules gives a clear price signal that the best way for a customer to take advantage of time-of-use rates is to shift usage to the off-peak period.

Lifeline Rates - The Settlement Agreement, in subsection XVI-E, provides for protection for customers taking electric service from TEP under low-income tariffs. Customers on lifeline rates will keep their current rates, and those rate schedules will be available for new lifeline customers. Lifeline tariffs will not be subject to the PPFAC. However, lifeline rate customers will be subject to the Renewable Energy Adjustor and the Demand-Side Management Adjustor.

Large General Service and Large Light and Power Rates - The rates for these service classes are seasonally differentiated and have substantial non-fuel cost recovery through demand charges. Shifting cost recovery to demand charges gives an incentive to customers to move usage from the peak period to off-peak periods, thereby helping the Company to control peak demand and reducing costs for all customers.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. Are you the same Frank Radigan who previously filed testimony in this proceeding?

A. Yes. I previously filed direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the scope of your testimony?

A. I will address the revenue allocation and rate design issues (rate spread, inclining block rate structure, time-of-use, other rate design changes, and low-income tariffs) contained in Section XVI of the Settlement Agreement. In addition, I will respond to Commissioner Gleason's letter of April 3, 2008, and to Commissioner Mayes' letter of May 20, 2008.

REVENUE ALLOCATION

Q. Please comment on the revenue allocation contained in the Settlement Agreement.

A. The Settlement Agreement at paragraph 2.3 provides for base rate revenue of $828.2 million, which is a $47.1 million base revenue increase over TEP's existing base rate revenue of $781.1 million. Settlement Exhibit 3 presents a Proof of Revenue that shows how the $828.2 million (inclusive of the $47.1 million base rate increase) has been spread across all rate schedules so that each schedule receives the same increase, except for residential customers that qualify for lifeline programs. These programs do not receive a rate increase. As shown on Settlement Exhibit 7, the $47.1 million base revenue increase has been spread across the service schedules so that all rate schedules, with the exception of the lifeline schedules, receive the same increase of 6.1 percent in adjusted base revenues. This results in an average residential class increase of 5.9 percent and average increases for the other customer classes of 6.1 percent. Existing and future customers that qualify for lifeline programs will not experience a rate increase. The revenue allocation shown on Settlement Exhibits 3 and 7 and described in subsection XVI-A of the Settlement Agreement is a reasonable resolution of the various proposals put forth by parties in their testimony. The revenue allocation is reasonable as it protects the lifeline customers from the rate increase while having a minimum impact on other classes.

RATE DESIGN

INCLINING BLOCK RATE STRUCTURE

Q. What is an inclining block rate structure?

A. An inclining block rate structure is one where the unit price of electricity, excluding the customer charge, increases as consumption increases. The Settlement Agreement introduces inclining block rates for Residential Rate 01 and General Service Rate 10.

Q. Please describe the inclining block rates for Residential Rate 01.

A. The Settlement calls for the rate structure for the primary residential service classification, Residential Rate 01, to be redesigned from a flat rate to an inclining block rate. The new rate will have three blocks, with the first block applicable to kWh usage from 0 to 500 kWhs, the second block for usage from 501 kWhs to 3,500 kWhs, and the third block for usage above 3,500 kWhs. The summer rate for the second block is about 2 cents per kWh higher than for the first block, and the rate for the third block is 2 cents per kWh higher than for the second block.

An inclining block rate structure is a means by which one may encourage energy conservation. As customer usage increases, the price for each kWh of electricity becomes more expensive, thereby giving the customer an incentive to consider using less power. The rates are also seasonally differentiated between summer and winter, with the winter rates lower than the summer rates. The seasonal differences will also make customers more aware that power costs are higher during the high-usage summer periods.

Q. Please comment on the introduction of inclining block rates for General Service Rate 10.

A. General Service Rate 10 shall be redesigned to have an inclining block structure with two blocks. The first block shall apply to the first 500 kWhs per month, and the second block shall apply to usage above 500 kWhs per month.

Similar to Residential Rate 01, many General Service Rate 10 customers are small users, with 30 percent of the usage in this rate class falling under 500 kWhs. For these customers, average usage is approximately 200 kWhs.

TIME OF USE RATES

Q. Please describe the proposed changes to the time-of-use rates that are provided in the Settlement Agreement.

A. Sub-section XVI-C of the Settlement Agreement addresses Time-of-Use Rates. The changes to the time-of-use rate structure are extensive and should be very beneficial in educating customers about the cost of power. I will describe all the changes and details of the rates and also explain why I believe they are reasonable.

The first change is that the current residential time-of-use rate schedules shall be frozen to new subscription. However, Rate 70 will remain open until December 31, 2008, for new and existing customers. The frozen rate schedules shall remain in place for existing customers, but new customers will not be eligible for service under these frozen schedules. It is appropriate to freeze these schedules because TEP will implement new time-of-use schedules that will be open for new subscription.

Second, under the proposed time-of-use rates, all residential, general service, large general service, and large light and power customers will be offered a time-of-use option.

TEP has also committed to designing a program to educate customers on the potential for load shifting and bill reduction under time-of-use rates, and will promote time-of-use so as to increase subscription thereto.

Q. Please describe the proposed time-of-use rates for residential customers.

A. TEP shall offer three new optional residential time-of-use schedules: 70N-B, 70N-C, and 70N-D. These rate schedules have identical on-peak, off-peak, and shoulder periods during the week, but differ on weekends. For each of these rate schedules, the time-of-use rate periods during the weekdays recognize the times and associated cost differences of supplying power throughout the day.

Q. What are the specific weekday time-of-use hours under Rates 70N-B, 70N-C, and 70N-D?

A. In the summer, the on-peak period is four hours long during the middle of the day when usage is the highest (2:00 p.m. – 6:00 p.m.). There are also shoulder periods (12:00 p.m. – 2:00 p.m. and 6:00 p.m. – 8:00 p.m.) that bookend the peak period, thereby recognizing that the costs associated with these shoulder periods fall between peak and off-peak costs. The off-peak period serves the remaining hours during the weekday (12:00 a.m. – 12:00 p.m. and 8:00 p.m. – 12:00 a.m.). In the winter, the on-peak periods are 6:00 a.m. – 10:00 a.m. and 5:00 p.m. – 9:00 p.m. The remaining hours are off-peak.

Q. Please describe proposed Rate 70N-B.

A. Rate 70N-B is known as the Weekend Shoulder rate. On summer weekends and selected holidays, the afternoon and evening (2:00 p.m. – 8:00 p.m.) shall be charged at the shoulder period rate. Thus, on weekends, the shoulder period will be six hours long with no peak period. In the winter, on weekends and selected holidays, there will be only an evening peak (5:00 p.m. – 9:00 p.m.) with the remaining winter weekend hours treated as off-peak.

Q. Please describe proposed Rate 70N-C.

A. Under Rate 70N-C, which is known as the Weekend Super-Peak rate, there will be no weekend and holiday shoulder. On summer weekends and selected holidays, there will be a four-hour peak period from 2:00 p.m. – 6:00 p.m., and all remaining weekend/holiday hours will be off-peak. On winter weekends and selected holidays, there will be a four-hour peak period from 5:00 p.m. – 9:00 p.m. with the remaining winter weekend/holiday hours treated as off-peak.

Q. Please describe proposed Rate 70N-D.

A. Under Rate 70N-D, which is known as the Weekends Off-Peak rate, all weekend and selected holiday hours will be off-peak.

Q. Please describe the new non-residential time-of-use rates.

A. The new non-residential time-of-use rates shall apply to each day of the year, with no distinction for weekdays, weekend days, or holidays. Peak demand charges, where they exist, will apply to periods designated as shoulder in addition to peak periods.

The non-residential time-of-use schedules will have a summer on-peak period from 2:00 p.m. – 6:00 p.m. and two shoulder periods from 12:00 p.m. – 2:00 p.m. and 6:00 p.m. – 8:00 p.m. Remaining summer hours will be off-peak. The winter peak period shall run from 6:00 a.m. – 10:00 a.m. and 5:00 p.m. – 9:00 p.m. Other winter hours shall be off-peak.

Q. Please comment on the proposed hours for the time-of-use rate schedules.

A. The selection of peak and shoulder hours was based on a statistical analysis of whether the load for a particular hour differs significantly from daily peak load. Whether a statistically significant difference exists depends on the mean and standard deviation of hourly load. Through this process, the Company classified the hours in the day as peak, shoulder, and off-peak. Shoulder hours applied only in the summer months (May through October).

I have reviewed the Company's statistical analyses, as well as the underlying load and cost data used to support them, I believe the conclusions are reasonable. The Company has expanded the shoulder period by including two more hours (12:00 p.m. – 2:00 p.m.). The Company also proposed a four-hour peak period (2:00 p.m. – 6:00 p.m.) as opposed to the current peak period (1:00 p.m. - 6:00 p.m.). The proposed four-hour summer peak period is sometimes referred to as the super-peak and consists of the hours when energy costs are at their highest. Having a shoulder period from May through October is an additional benefit because it encourages customers to move usage away from the Company's peak, which generally occurs around 4:00 p.m. Even if a customer cannot move usage to the off-peak period, he may still benefit by shifting usage to the shoulder period, which would be a benefit for transmission and capacity planning. Many other utilities use peak, shoulder, and off-peak periods to design rates.

Q. Please comment on the reasonableness of the new time-of-use rates.

A. One way to reduce peak demand is for customers to shift usage for non-critical needs to the off-peak period. The Company is offering three new residential time-of-use options, each with different treatment as to peak and shoulder periods on weekends and holidays. Maximizing the number of options for customers will allow them to choose a rate schedule fitting their lifestyle and resulting in load shifting that will be beneficial to system operations. For example, if a customer can save money by washing clothes or dishes on the weekend, he will have a greater incentive to do so.

Sending price signals to customers as to how TEP's cost to serve may vary at different times of the year and at different times of the day provides an important energy-conservation incentive. Thus, expanding the availability of time-of-use rate schedules is in the public interest. It is important to note that all time-of-use rate schedules shall be available on an optional basis and will not be mandatory for any customer.

In order for customers to clearly see the advantages of shifting power to the off-peak period, it is important for the time-of-use rates to be easy to compare to the non-time-of-use schedules. For this reason, each time-of-use option will have the same inclining block rate structure as the comparable non-time-of-use schedule.

In addition, the rates for the shoulder periods are approximately the same as the rates for the non-time-of-use schedules. The rates for the peak periods are higher than the rates for the non-time-of-use schedules. The rates for the off-peak periods will be lower than the rates for the non-time-of-use schedules. These features will make it easier for customers to understand the time-of-use schedules and to evaluate their potential benefits.

OTHER RATE DESIGN CHANGES

Q. Could you please discuss the rate design changes for the Large General Service and Large Light and Power rates?

A. Yes. The Time-of-Use Rates for Large General Service Rate 85N and Large Light and Power Rate 90N shall be seasonally differentiated and shall have substantial non-fuel cost recovery through demand charges. These changes were requested by representatives of these customers during the course of this proceeding. These rate design changes will not only give these customers an opportunity to reduce costs, but will also provide benefits to the Company and its other customers. By shifting cost recovery to demand charges, customers will have an incentive to move usage from the peak period to off-peak periods. Shifting usage will help the Company to control peak demand and therefore reduce costs for all customers.

LOW-INCOME TARIFFS

Q. Could you please comment on rate design for lifeline customers?

A. Yes. The Settlement Agreement holds both existing and future low-income customers harmless from the 6percent base rate increase. As a result, all rate schedules, except for the low-income schedules, will receive a 6.1 percent increase.

In addition, the lifeline tariffs will not be subject to the PPFAC. Lifeline customers will, however, be subject to the Renewable Energy ("REST") Adjustor and the Demand Side Management ("DSM") Adjustor, and the application of the DSM adjustor will result in a small rate increase for these customers.

RESPONSE TO COMMISSIONER GLEASON'S LETTER DATED APRIL 3, 2008

Q. Are you aware that on April 3, 2008, Commissioner Gleason placed a letter in the Docket requesting that the parties respond to questions regarding the rate design for the Residential class and the time-of-use rates?

A. Yes, Chairman Gleason asked the parties to respond to the following questions regarding the rate design for the residential class and the time-of-use rates. The answers to Chairman Gleason's questions are set forth below:

Question:

1. For the residential class:

A. What is the monthly median summer (May-October) usage in kWhs?

Answer:

The monthly median summer usage is 692 kWhs.

Question:

B. How were the tier breakpoints (500 kWhs and 3,500 kWhs) chosen?

Answer:

The break points proposed for the Residential Rate 01 are based upon TEP's customer usage data. For the summer period, the first tier of 0 to 500 kWhs captures the usage for 25 percent of the bills and comprises 7 percent of the total usage. For the winter period, that tier captures the usage for 46 percent of the bills and comprises 20 percent of the total usage. In the summer, 32 percent of the bills (comprising 22 percent of the usage) fall within 500 to 999 kWhs, and 19 percent of the bills (comprising 23 percent of the usage) fall within 1000 to 1499 kWhs. Together, these two usage categories, which cover usage from 500 to 1499 kWhs per month, comprise 51 percent of the annual usage and 45 percent of the usage for the summer period. In other words, most of the summer usage falls within the 500 to 1,499 kWhs per month range.

Given this information, the 0 to 500 kWhs per month usage level represents a natural cut-off point for designing an inclining block rate, as it covers the usage for the smallest of customers. The charge for these customers should not include any premium to encourage conservation. In Staff's view, usage above 500 kWhs is a natural point to start encouraging conservation.

The last tier (usage above 3,500 kWhs per month) captures fewer than 1percent of the bills and comprises 4 percent of the usage in the summer period. On an annual basis, this category captures 0.1 percent of the bills and comprises 1.2 percent of the usage. While these figures may appear small, one must recognize that there are 30,000 bills issued during the summer period for usage above 3,500 kWhs per month. From Staff's perspective, it is especially reasonable to encourage conservation among these large users.

Question:

C. How were the rate differentials chosen for the second tier (501 kWhs – 3,500kWhs) and the third tier (3,501 kWhs and above)?

Answer:

The rate for the second tier is about 2 cents per kWh higher than for the first tier, and the rate for the third tier is 2 cents per kWh higher than for the second tier. Rate differentials between small and large users are designed to encourage conservation. High energy users generally have a higher concentration of high-usage appliances, such as pool pumps and air conditioners, while low users generally do not have a significant potential for decreasing their usage.

Question:

2. *For the residential class Time-of-Use ("TOU") rates:*

   A. How were the hours chosen for the off-peak, shoulder, and peak hours?

Answer:

The selection of peak and shoulder hours was based on a statistical analysis of whether the load for a particular hour differs significantly from daily peak load. Whether a statistically significant difference exists depends on the mean and standard deviation of hourly load. Through this process, the Company classified the hours in the day as peak, shoulder, and off-peak. Shoulder hours applied only in the summer months (May through October).

Question:

B. How were the rate differentials chosen between each set of hours?

Answer:

The rates for the shoulder periods are approximately the same as the rates for the non-time-of-use schedules. The rates for the peak periods are higher than the rates for the non-time-of-use schedules. The rates for the off-peak periods will be lower than the rates for the non-time-of-use schedules. These features will make it easier for customers to understand the time-of-use schedules and to evaluate their potential benefits.

Question:

C. How were the rate differentials chosen within each set of hours?

Answer:

For each of the new TOU rate schedules, there is a differential between the shoulder period and the off-peak period. These differentials are approximately 0.9 cents per kWh for the 0 to 500 kWhs block and 1.2 cents per kWhs for the 501 to 3,500 kWhs block. The rate for the shoulder period is approximately the same as the rate for the non-TOU rate schedule.

RESPONSE TO COMMISSIONER MAYES' LETTER DATED MAY 20, 2008

Q. Are you aware that on May 20, 2008, Commissioner Mayes placed a letter in the Docket requesting that the parties address in testimony or settlement the issues raised in that filing?

A. Yes. I have reviewed the above-referenced letter. I will address the topic of time-of-use. The other topics raised in the letter will be addressed by other Staff witnesses.

Q. Please comment on Commissioner Mayes' request that the parties to the Settlement file a TOU tariff that provides customers a reasonable opportunity to pay reduced rates by shifting their usage to off-peak periods.

A. Consistent with subsection XVI-C of the Settlement Agreement, TEP has agreed to offer three new optional residential TOU rates, as well as optional TOU rates for non-residential customers. Staff believes this rate design addresses the issue raised in Commissioner Mayes' letter. For example, a customer choosing rate 70N-C could save $10.21 per month (9.9 percent less than under the non-TOU rate schedule) by moving 1,000 kWhs of usage to the off-peak period. A certain amount of savings would likely result just by switching to service under any of the new TOU rate schedules, since at least 60 percent of the TOU hours are off-peak. Substantial savings could accrue from efforts by the customer to shift usage away from the peak and shoulder periods.

Q. Does this conclude your testimony?

A. Yes, it does.